# EPA RESPONSE TO

Summary of Interagency Working Comments on Draft Language under EO12866/13563 Interagency Review. Subject to Further Policy Review.

**Environmental Protection Agency (EPA): Proposed Rule**

**Oil and Natural Gas Sector: Emission Standards for New and Modified Sources**

**RIN 2060-AS30**

**General Comments:**

1. Reviewer recommends providing additional explanation why EPA is not proposing the "less stringent" option (Option 1) as it provides $100 million greater net benefit than EPA's proposed option.

   EPA RESPONSE:
   Please see the discussion in preamble section VIII.F. Well completions conducted using REC in combination with combustion achieves not only methane and VOC emission reductions but results in recovery of natural resources. Furthermore, the use of traditional combustion control devices alone, present local emissions impacts. Although combustion alone may be less costly than recovery, we believe that it is important to conserve precious natural resources in addition to controlling emissions.

2. Reviewer recommends providing a table near the front that provides the proposed requirements including EPA's preferred approach(s) (including compliance options), what exemption thresholds are, and approaches EPA is taking comment on.

   EPA RESPONSE:
   EPA will provide this type of information as part of its public outreach materials on the proposal (e.g. fact sheets).

3. Reviewer recommends updating estimates based on the AEO 2015 data. To extent that it is not practicable to use the most recent publicly available data, EPA should provide an explanation of why that data was not used and provide a qualitative discussion as to any potential significant changes that could occur from the newest data.

   EPA RESPONSE:
   We will explore updating the impacts analysis to the AEO 2015 for the final analysis. Putting a qualitative suggestion about potential changes in forecasted activities is a good suggestion and we will do this for the final draft of the RIA for this proposal. We are currently not in a position to write this, but a placeholder has been added on page 3-8 where this will be presented.

4. In discussing the comparison of GHG emissions saved from this regulation to the GHG emissions of various countries, reviewer recommends clarifying whether the emissions of the other 140+ countries are compared individually or in combination. Reviewer also recommends clarifying whether EPA is comparing oil and gas sector emissions between countries or whether EPA is comparing U.S. oil and gas emissions to the total $CO_2$ -



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equivalent emissions from all sources other countries. See page 83.

EPA RESPONSE:
Clarified that this is referring to the national-level, individual emissions for all anthropogenic sources from the 140 countries.

"Ranking U.S. emissions of GHGs from oil and natural gas production and natural gas processing and transmission against total GHG emissions for entire countries, show that these emissions would be more than the national-level emissions totals for all anthropogenic sources for Greece, the Czech Republic, Chile, Belgium, and about 140 other countries"

5. Reviewer recommends clarifying whether the standards apply to gather and boosting stations, specifically in relation to fugitive emissions.

EPA RESPONSE:
Language was added to the Section VIII.G. in order to clarify that the collection of fugitive emissions components at gathering and boosting stations are a part of compressor stations and are subject to the fugitive emissions standards.

"The detection of fugitive emissions from oil and natural gas well sites (e.g. well sites) and compressor stations, which are comprised of compressors at natural gas transmission, storage, gathering and boosting stations, can be determined using several technologies."

6. Reviewer recommends providing a reference to the Methane Challenge Program, preferably within the section discussing an exemption from the fugitive emissions monitoring requirements for sources with corporate-wide emissions monitoring programs. Also, consider requiring the owner or operator also repair the emissions as part of the voluntary program.

EPA RESPONSE:
As noted in section IV.C. of the preamble, we intend to encourage corporate-wide efforts to achieve emission reductions through transparent and verifiable voluntary action that would obviate the burden associated with NSPS applicability. Specifically, we are taking comment (section VIII.G.) on potential ways to encourage broadly applied fugitive emissions monitoring and repair programs including whether well sites or compressor stations should not be affected facilities if the owner or operator has a corporate-wide fugitive emissions monitoring and repair plan in place. We are thus seeking input on a range of ways to encourage fugitive emissions monitoring and leak repair. Because it is still in the proposal/development stages, we feel a specific reference to the Methane Challenge Program is premature.

7. Reviewer recommends providing a discussion on how the federal NSPS regulations may affect current state regulations (e.g., Colorado, Wyoming, and Pennsylvania) and what

actions states can take that go beyond federal regulations.

EPA RESPONSE:
The EPA wants to avoid situations in which federal rules have adverse effects on implementation of state rules. To that end, EPA reviewed existing state and local regulations and consulted with state, local and tribal governments during development of the oil and natural gas NSPS to help inform the regulatory process. The NSPS regulations do not preempt states from having more stringent requirements.

8. Reviewer recommends providing additional previous regulations when EPA has interpreted §111(b)(1)(A) to provide the authority to establish a standard of performance for any pollutant emitted by that source category as long as EPA has a rational basis for setting a standard for the pollutant. See page 46.

   EPA RESPONSE:
   EPA will add a reference to the preamble in section VI.

9. Reviewer recommends providing additional discussion for the multipollutant cost-effective approach why the costs have been split equally between VOC and methane. Specifically, why the approach chosen was used, whether other approaches are possible, and how this approach could be expanded to all other pollutants emitted within the Oil and Gas sector.

   EPA RESPONSE:
   We believe the discussion in the preamble (VIII.A) of the multipollutant cost-effectiveness approach is thorough. Additionally, we are requesting comment on the approaches to estimate cost-effectiveness for emissions reductions using multipollutant controls assessed in this action.

10. Reviewer recommends ensuring that when the term "worst case scenario" is used that it is actually a worst case and not a conservative scenario.

    EPA RESPONSE:
    We agree and replaced the term "worst case scenario" with "conservative scenario."

11. Reviewer recommends providing "findings" for both cost-effective approaches (single pollutant and multipollutant) for all potential regulatory areas. For example, there is no finding on the single pollutant approach on page 169.

    EPA RESPONSE:
    Detailed discussion and analysis of all control options are included in the TSD. For example, analytical results for pneumatic pumps are presented in sections 7.3 and 7.4 of the TSD.

12. Reviewer recommends providing additional clarification for the choice of 300 scf/barrel



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for the threshold as the GOR as non-volatile "black oils" are generally defined as having GOR values in the range of 200 to 900 scf/barrel.

EPA RESPONSE:
We've added a footnote to clarify this: "On February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137."

13. Reviewer recommends clarifying that for those actions that appear to be one-time (e.g., well completions) why it is appropriate to consider the cost-effectiveness on an annual cost basis.

EPA RESPONSE: The completion requirements (combustion and reduced emission completions) are essentially one-time events and are generally performed by independent contractors. The emissions controls are applied over the course of a well completion. The duration of the well completion will typically vary by well. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later, if at all. After the completion is concluded, the REC equipment is typically moved by contractors to be reused during other well completions. Given that we base our REC costs on the average cost for contracting the REC as a service, we expect contractors' operation and maintenance costs, depreciations, and potential salvage value of the equipment to be reflected in the total contracting costs. Because of these factors, we decided to treat the hydraulically fractured oil well completion requirements solely as annualized costs.

14. Reviewer recommends providing additional information on the emissions that would be created and/or released from any of the proposed control options, including any emission data and whether they have been monetized in the consideration of the cost-effectiveness. If they have not been monetized, EPA should provide a discussion as to why those emissions have not been monetized and provide a qualitative discussion of the impacts.

EPA RESPONSE:
We believe the information provided in the preamble and in the TSD concerning secondary impacts sufficiently characterizes them. With respect to the monetization, EPA has not presented disbenefit estimates in tabular form due to the uncertainties. Please see the RIA pages 4-37 to 38, which provides EPA's rationale for not monetizing the $CO_2$ disbenefits, presents one potential approach (including details of the alternative calculation) for estimating those disbenefits, and lists the estimated adjusted amount in the text. EPA is also taking comment on this approach. EPA will consider the comments received and based on that input, determine whether it is appropriate to include the estimates in tabular form and the rulemaking's primary benefit-cost comparison.

15. Reviewer recommends providing the methane reduction in tons whenever the emission reduction is provided in $CO_2e$ (e.g., page 296).

EPA RESPONSE:
We supplemented Table 3 with information on methane emissions in tons, not just $CO_2$ Eq.

16. Reviewer recommends accounting for the $CO_2$ disbenefits from this regulation.

    EPA RESPONSE:
    Please see response to comment #14 above.

17. Reviewer recommends splitting out the gross cost of compliance from the net cost of compliance in the preamble followed by an explanation of the assumptions that were used to calculate the offset from the sale of the captured gas and offset for the final net cost. For example, a discussion should be included to describe the extent to which regulatory structures, infrastructure constraints and/or other unique circumstances may prevent regulated entities from readily monetizing the value of gas that is not emitted as a result of compliance with this proposed rule. The calculation of the offset should be as well defined as the initial cost itself (see page 22).

    EPA RESPONSE:
    We revised preamble section XI.C "What are the compliance costs?" to include more information about revenues from product recovery, as well as a simple sensitivity analysis.

18. Reviewer recommends clarifying that while the Endangerment finding in 2009 only reviewed six well-mixed GHGs that there are more than six GHGs and not all of them are well-mixed (see page 31). Reviewer also recommends that similar language on page 77 be clarified to reflect this.

    EPA RESPONSE:
    EPA has provided clarification to the text in section IV.C. and VI.A.2.

Well Completions:

1. Reviewer recommends providing the marginal cost-effectiveness of requiring RECs alone (90% control of emissions) to REC with completion combustion device (95% control of emissions). If the REC with completion combustion device is not as cost-effective as the RECs alone, reviewer recommends providing additional justification for why EPA chose that option.

   EPA RESPONSE:
   We don't think this cost comparison is necessary. As discussed in section VIII.F.1., we determined that REC alone would not be BSER because of the initial gas produced from the well may not meet quality specifications for entering gathering lines, and as a result, the gas must be either vented or combusted. REC combined with combustion is estimated

to provide 90 percent product recovery and 95 percent overall emission reduction. Combustion alone would result in no product recovery.

2. Reviewer recommends providing additional discussion of the benefits of using REC versus just flaring for well-completions (Section VII.F).

   EPA RESPONSE:
   Please see the response to question #1 in the "general comments" section of this response to interagency review document.

Pneumatic Pumps:

1. (a)Reviewer recommends clarifying why standards for pneumatic pumps are limited to sites where a control device is already available onsite. (b)Reviewer also recommends including control requirements for sites that do not currently include control devices, how this punishes early actors, and how enforcement of this standard would work. (c)Also, page 170 does not include the caveat that it is only at sites that currently have control devices.

   EPA RESPONSE:
   (a)Although there are several options for reducing emissions from pumps, we identified that some of these options are not broadly applicable. The remaining one option available is routing emissions to a process or control device. Based on our BSER analysis, we believe that the cost is excessive if the process or control device does not currently exist. Please see the discussion in section VIII.E. However, cost is not excessive for routing to existing process or control device on site. For segments of the industry, we believe that existing processes or combustors already are in common use. See example of storage vessels in section VIII.E. (b) We are proposing requirements for when a control device is not on site, facilities would need to submit an initial and annual certification that no device is on site and comply with the standard within 30 days of installing a device and reporting such in the next annual report. (see §60.5393a(b)(2)(i) and (ii)). We also encourage operators to use other options than natural gas-driven pneumatic pumps where their use is technically feasible. To incentivize the use of such alternatives, we propose that defining "pneumatic pump affected facility" (see §60.5365(h) ) to include only natural gas-driven pumps. As a result, pumps which are driven by means other than natural gas would not be affected facilities subject to the pneumatic pump provisions of the proposed NSPS. (c) We believe that this is clearly stated in section VIII.E.

Fugitive Emissions:

1. Reviewer recommends providing additional information on how semiannual monitoring is BSER. It is unclear how semiannual monitoring is BSER over quarterly or yearly monitoring. Reviewer also recommends taking comment on other alternative approaches to leak surveys that are more akin to approaches taken by Colorado and Wyoming.

EPA RESPONSE:
Please see the revised discussion in section VIII.G. and additional text to solicit comment on other approaches. We are soliciting comment on the use of Method 21, which is one of the options that Colorado allows in Rule 7; however, we are concerned with the ambiguity of the "other Division approved instrument based on monitoring device or method" provision. There are no operational requirements to ensure that leaks can consistently be found during monitoring with such an instrument. In addition to Method 21, we are soliciting comment on other potential leak detection approaches.

2. Reviewer recommends providing additional discussion on what different assumptions were made for the OGI monitoring to have a change in efficiency from quarterly surveys (80% emissions reduction) to annual surveys (40% emission reduction) and what the ranges of emissions reduction are within each of these estimates. Specifically, it does not appear that EPA has a justification for these assumptions and should provide sensitivities on these assumptions and how they would change the final determinations.

   EPA RESPONSE:
   The preamble states that information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of surveys performed and different assumptions made by the study authors. We used engineering judgment to identify anticipated percent reduction based on frequency. We believe that 40%, 60%, and 80% are adequately representative of the reduction we would expect with increased frequencies of survey.

3. Reviewer recommends allowing Method 21 as an acceptable compliance option to OGI. As there are significantly different capital costs for these two methods, but do not appear to be any emission reduction differences, EPA should allow companies to choose a less capital-intensive option.

   EPA RESPONSE:
   We are taking comment on this in section VIII.G.

4. Reviewer recommends that EPA also propose allowing flexibility to enable the use of continuous emissions monitoring systems and mass flow rate thresholds for compliance. Reviewer recommends using mass flow rate as it is a better measure of emissions rate since it can account for ambient conditions (e.g., wind, temperature) and discriminate among methane sources.

   EPA RESPONSE:
   The CEMS technology is not used to determine the presence of fugitive emissions nor does EPA believe that CEMS are appropriate to be used in this case. Fugitive emissions are inconsistent by nature and come from various emissions points. CEMS are typically used on a source emission stack (e.g. boiler).

5. Reviewer recommends providing additional context of fugitive emission leakage to one percent of components by providing EPA's estimate of the number of components that typically leak at uncontrolled facilities.

   EPA RESPONSE:
   Please see the revised section VIII.G. EPA will provide this additional context in the technical support document.

6. Reviewer recommends providing further discussion of the distribution of fugitive emissions between components throughout a facility along with a statement on why it is preferable to conduct comprehensive facility surveys as opposed to surveying just those components most likely to be large emissions sources. See page 240.

   EPA RESPONSE:
   While we do think we adequately discuss that that the monitoring technologies (e.g. OGI) have the capacity to analyze a significant number of components per hour and because components can be surveyed simultaneously cost is reduced, we have added a short discussion on the distribution of fugitives and why comprehensive surveys are more beneficial than only surveying large components. Please see additional discussion in section VIII.G.

7. Reviewer recommends that the proposed regulation text cross-reference the section that provides guidance on who should be the recipient of the annual reports on fugitive emissions. See page 376.

   EPA RESPONSE:
   Please see cross reference added in section 60.5401a of the regulatory text.

8. Reviewer recommends that EPA take comment on the appropriate mass flow rate that should be used for leak detection and under what circumstances this could be used to meet compliance. Reviewer notes that a mass flow rate (scfh) is preferable to a concentration measurement (ppm), which is a less accurate measurement of leaks since it does not consider the impact of atmospheric conditions, such as wind or background methane.

   EPA RESPONSE:
   This request does not make sense in the context of this action. This is not how fugitives are measured or occur.

9. Reviewer recommends creating a performance-based or approval approach for fugitive emission detection technologies to allow for new technologies that may provide equal to or greater emissions reductions than OGI or Method 21.

   EPA RESPONSE:

We agree that we should encourage continued development of new technologies, but also need BSER to be adequately demonstrated. We are required to identify and consider existing control options in order evaluate BSER. Without first identifying the control options, which is being suggested, it would be extremely challenging to identify BSER. We are soliciting comment on other approaches, see section VIII.G.

10. Reviewer recommends clarifying if the methodology for monitoring and reporting of fugitive emissions is sufficient given that much of the emissions come from super-emitters.

    EPA RESPONSE:
    We believe that the methodology for surveying, repairing, and reporting fugitives is sufficient and that the OGI is optimized if all the parameters are met.

11. Reviewer recommends providing additional clarification of any potential perverse incentives for operators to avoid finding or reporting leaks in relation to monitoring and reporting fugitive emissions.

    EPA RESPONSE:
    Please see our response to comment number 10. Our response is the same here.

12. Reviewer recommends providing additional explanation as to why 15 days is an appropriate requirement for repairing a leak and allowing for delays in repair due to unforeseen events such as inclement weather and/or equipment supply chain distributions. Reviewer also recommends taking comment on whether a longer or shorter time-frame should be allowed for repairs. See page 468 and 473.

    EPA RESPONSE:
    A footnote providing additional explanation has been added to the preamble. See VIII.G. This is also where we request comment on the appropriateness of this timeframe.

13. Reviewer recommends proposing a threshold less than 10,000 ppm for Method 21 technologies (see page 240) as there are many forms of technology that can meet lower detection thresholds.

    EPA RESPONSE:
    We request comments on the appropriateness of this threshold in section VIII.G.

Liquids Unloading:

1. Reviewer recommends considering best practices for reducing emissions from liquids unloading and taking comment on whether performance standards for liquids unloading is appropriate.

   EPA RESPONSE:

Any new source performance standard (including "best practices") under section 111 of the CAA, whether it is a numerical emission standard or a work practice or operational standard under section 111(h), must reflect the best system of emission reduction (BSER). In determining BSER, the EPA must identify technology or practices that can be applied universally. As discussed in the preamble, liquids unloading operations are highly variable and differ based on individual well characteristics. As a result, we were unable to identify universally applicable technologies or practices that represent BSER at this time.

2. Reviewer recommends providing additional clarification why EPA is unable to propose standards for liquid unloading operations.

   EPA RESPONSE:
   See response above.

**Specific Comments:**

1. Executive Summary. (a) Reviewer recommends clarifying whether the standards apply to source categories in the transmission segment. (b) Reviewer also recommends considering adding a reference to the Climate Action Plan and the Methane Strategy.

   EPA RESPONSE:
   (a) Please see the clarification added in section II.A.
   (b) References to the Climate Action Plan and the Methane Strategy are in section IV.C.

2. Executive Summary. Reviewer recommends providing discussion of the standards for subcategory 1 and 2 wells within the executive summary (see page 97).

   EPA RESPONSE:
   Please see clarification in section II.B.

3. Page 13. Reviewer recommends providing a citation for the 2009 GHG endangerment finding.

   EPA RESPONSE:
   Please see the citation added in section II.A.

4. Page 14. Reviewer recommends clarifying whether regulated entities already complying with the 2012 Oil and Gas NSPS are in compliance with the proposed regulation.

   EPA RESPONSE:
   Affected facilities subject to the 2012 NSPS (40 CFR part 60 subpart OOOO) remain subject to 40 CFR part 60 subpart OOOO unless they are modified or reconstructed after the date of publication of the proposed 40 CFR part 60 subpart OOOOa rule. 40 CFR part 60 subpart OOOOa would apply to facilities that are new or modified after the proposal



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date. Facilities would not have to comply with 40 CFR part 60 subpart OOOOa until 60 days after publication of the final rule. Sources who comply with the new subpart 40 CFR part 60 subpart OOOOa are deemed to be in compliance with 40 CFR part 60 subpart OOOO. We include language to this effect in the proposed revisions to the regulatory text of 40 CFR part 60 subpart OOOO in this action.

5. Page 16. Reviewer recommends clarifying "across the source category" within the compressors section. Specifically whether it includes storage.

   EPA RESPONSE:
   The "transmission and storage segment" includes both natural gas transmission facilities and natural gas storage facilities. Please see clarification added in section II.B.

6. Page 18. Reviewer recommends clarifying up front who is required to perform the monitoring for fugitive emissions, whether leaks are required to be reported, and how long the entity has to fix the leaks that are identified.

   EPA RESPONSE:
   Please see the clarification added to Section II.B.

7. Page 18. Reviewer recommends clarifying the language within the hydraulically fractured oil well completions as to when exemptions apply and what the requirements are.

   EPA RESPONSE:
   Please see the clarification added to Section II.B.

8. Page 19. Reviewer recommends adding a reference to the Methane Challenge Program.

   EPA RESPONSE:
   Because it is still in the proposal/development stages, we feel a specific reference to the Methane Challenge Program is premature.

9. Page 19. Reviewer recommends defining the term "corporate-wide." Specifically whether a corporation would need to cover emissions in other countries.

   EPA RESPONSE:
   Section VIII.G. of the preamble and §60.5397a of the regulatory text outlines the items that a monitoring plan would need to included. We do not think a formal definition is necessary.

10. Page 19. Reviewer recommends revising the sentence to state as follows:
    a. In addition, we solicit comment on the whether new or modified well sites or compressor stations should not be affected facilities subject to the fugitive emission standards, if the owner or operator is implementing a corporate-wide fugitive

emissions monitoring **and repair** plan which is legally and practically enforceable.

EPA RESPONSE:
This change has been made.

11. Page 19. Reviewer recommends clarifying that when a unit is required to perform quarterly scheduled surveys, that if two consecutive surveys find less than one percent whether the unit would move to semi-annual or annual survey.

EPA RESPONSE:
Please see the clarification added to Section II.B.

12. Page 21. Reviewer recommends providing additional clarification on the term "perceived adverse effects" in relation to whether EPA believes these, or any part thereof, are actual adverse effects.

EPA RESPONSE:
Please see the clarification added to Section II.C.

13. Page 22. Reviewer recommends providing additional clarification on the benefits and the costs outside of 2020 and 2025, why they are not included, and if they were included, how they would calculated.

EPA RESPONSE:
In estimating and presenting benefits and costs for air rules, the EPA generally presents estimates based on a single analysis year, a year that is far enough into the future that the new regulation has come into full effect. For this proposed NSPS, we present two years of analysis, 2020 and 2025, in order to better characterize the effects of the NSPS over time. As described in the RIA, impact estimates in 2020 approximate early impacts of the program, and 2025 represents impacts after new sources have accumulated in the program, such that impacts, benefits and costs, are likely to increase with time.

14. Page 23. Reviewer recommends clarifying the discussion of non-monetized benefits because, as written, it gives the appearance that methane was not monetized in the rule.

EPA RESPONSE:
Please find clarifying text in Section II.C. "The EPA was unable to monetize all of the benefits anticipated to result from this proposal. The only benefits monetized for this rule are methane-related climate benefits. However, there would be additional benefits from reducing VOC and HAP emissions, as well as additional benefits from reducing methane emissions because methane is a precursor to global background concentrations of ozone. A detailed discussion of these unquantified benefits are discussed in section XI of this document as well as in the RIA available in the docket."

15. Page 31. Reviewer recommends clarifying what "LDAR for open-ended valves or lines,



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compliance period for LDAR for newly affected process units" means.

EPA RESPONSE:
This discussion describes the list of issues from the 2012 NSPS that we are granting reconsideration on. Additional discussion can be found in section IX.B.

16. Page 35. Reviewer recommends revising the sentence to state as follows:
    a. Building on the 2012 NSPS, the EPA intends to encourage corporate-wide efforts to achieve emission reductions through transparent and verifiable voluntary action that ~~obviate the burden associated~~ **would make it easier to comply** with NSPS **standards** ~~applicability~~.

EPA RESPONSE:
We decline these edits as they change the intended meaning of the sentence. We believe it is important to preserve the concept that well sites and compressor stations included in such corporate-wide fugitive emissions monitoring and repair programs would be excluded from NSPS affected facility status altogether.

17. Page 36. Reviewer recommends clarifying what "no set regulatory criteria for making such determination" means.

EPA RESPONSE:
Removed unclear text.

18. Page 40. Reviewer recommends clarification on footnote 7 about whether the Kraft Pulp Mill NSPS was adding an additional emission to be regulated as in this rule.

EPA RESPONSE:
Please see clarification in footnote 7.

19. Page 80. Reviewer recommends providing Table 3 in both Methane and $CO_{2e}$ instead of just in $CO_{2e}$.

EPA RESPONSE:
Please see additional table provided in Section VI.A.

20. Page 87. Reviewer recommends providing additional clarification with how the peer review and public submissions have been used in both the development of this proposed rule and any modifications to the white papers.

EPA RESPONSE:
Please see clarification in Section VI.B. "The peer review and public comments on the white papers included additional technical information that provided further clarification of our understanding of the emission sources and emission control options. The comments also provided additional data on emissions and number of sources, and pointed

out newly published studies that further informed our emission rate estimates. Where appropriate, we used the information and data provided to adjust the control options considered and the impacts estimates presented in the 2015 TSD."

21. Page 99. Reviewer recommends clarifying whether low pressure gas wells are exempt from the proposed rule.

    EPA RESPONSE:
    Please see clarification in Section VII.F.

22. Page 101. Reviewer recommends clarifying the list provided is a comprehensive list of fugitive emissions components and, if so, whether comment should be taken to determine if other components should be included or removed.

    EPA RESPONSE:
    Please see clarification in Section VII.G.

23. Page 102. Reviewer recommends clarifying the following sentence as it is unclear:
    a. The proposed standards would require replacement or repair of components if evidence of fugitive emissions is detected during the monitoring survey through visual confirmation from OGI

    EPA RESPONSE:
    Please see clarification in Section VII.G.

24. Page 109. Reviewer recommends clarifying how often a compressor is added to a compressor station.

    EPA RESPONSE:
    It is our understanding that compressors are rarely added to a compressor station. An analysis of the RBLC database found that for NAICS 221210 (Natural Gas Distribution) there were two permits in the last 10 years for modifications to existing compressor stations. For NAICS 486210 (Pipeline Transportation of Natural Gas), there were five modifications to existing compressor stations during the same period. Note that these counts do not include modifications that did not require a PSD/NSR permit, new facilities, or facilities that are not compressor stations such as natural gas processing plants or LNG facilities.

25. Page 125. Reviewer recommends providing references for when the "multipollutant cost-effective" approach has been used by EPA in previous rulemakings.

    EPA RESPONSE:
    Please see footnote 43.

26. Page 126. Reviewer recommends providing the basis for using a natural gas price of

$4.00/Mcf.

EPA RESPONSE:
Please see footnote 44.

27. Page 165. Reviewer recommends providing cost information in relation to areas that do not already have an existing control device or, if not appropriate, stating why that information is not provided.

EPA RESPONSE:
We clarified this text in Section VII.E.

28. Page 161. Reviewer recommends clarifying what "process" means in the following sentence:
    a. During our review of the Wyoming state rule covering pneumatic pumps, we identified an additional mitigation option for reducing emission from piston and diaphragm natural gas-driven pumps, which involves routing the gas to a **process** or routing the gas to a combustor (often done as part of the storage vessel control system).

EPA RESPONSE:
We clarified this text in Section VII.E.

29. Page 163. Reviewer recommends clarifying the basis for the assertion that 95 percent reduction in emissions of methane and VOC due to the control options imposed for the production and transmission and storage segments of routing natural gas-driven pump emission to a process or control device.

EPA RESPONSE:
We clarified this text in Section VII.E.

30. Page 167. Reviewer recommends clarifying the sentence "Because instrument air systems are known to be used at natural gas processing plants. . . ." whether EPA is assuming that all, most, or some other deviation of processing plants use instrument air systems. If it is not all, reviewer recommends providing additional information why EPA assumes that it is incremental.

EPA RESPONSE:
We clarified this text in Section VII.E.

31. Page 167. Reviewer recommends clarifying the following sentence as it is unclear:
    a. We determined that the annualized cost of control for routing to a process are similar to the costs presented above for both a new and existing VRU

EPA RESPONSE:



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We clarified this text in Section VII.E.

32. Page 180. Reviewer recommends clarifying why the cost of performing REC are provided as a range of costs ($700 - $6,500/day) but the estimated cost for a 3-day completion is only provided as a single number ($17,183).

    EPA RESPONSE:
    Please see clarifying text in Section VII.F. "Equipment costs associated with RECs will vary from well to well. Costs of performing REC are projected to be between $700 and $6,500 per day, varying based on if key pieces of equipment are readily available on site or temporarily brought on site. Based on the 2012 NSPS evaluation, the average cost of a REC combined with completion combustion device for a 7-day completion event was $33,327. Under our evaluation in this action, we estimate the cost for a REC combined with a completion combustion device for a 3-day completion event to be $17,183. However, in both cases, there are savings associated with the use of RECs because the gas recovered can be incorporated into the production stream and sold. With the consideration of gas savings, the cost of a REC combined with a completion combustion device for a 7-day completions event for a gas well was estimated to have a net savings. With the consideration of gas savings, the cost of a REC combined with a completion combustion device for a 3-day completions event for an oil well was estimated to be $13,586."

33. Page 187. Reviewer recommends providing reference to any guidance material that exists or is planned for how an operator can show or determine whether a control option is "technically infeasible." If there is no guidance, EPA should explain how the evaluation for this would be made.

    EPA RESPONSE:
    Please see clarifying text in Section VII.F. "Conditions that could prevent proper operation of the separator include insufficient gas concentration, low pressure gas, and multiphase slug flow containing solids that could clog the separator."

34. Page 195-96. Reviewer recommends clarifying the statement on page 195 that "emissions cannot be controlled or measured" when emissions numbers appear to be provided on page 196.

    EPA RESPONSE:
    Deleted unclear text.

35. Page 217. Reviewer recommends providing additional information why EPA believes that available supply of qualified contractors and OGI instruments will be available for semiannual surveys. With semiannual surveys based on the establishment of the new source, what kind of limitations could occur with semiannual surveys?

    EPA RESPONSE:



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EPA is taking comment on the availability of OGI operators. "We solicit comment on both the availability of OGI instruments and the availability of qualified OGI technicians and operators to perform surveys and repairs."

36. Page 242. Reviewer recommends explaining what a "subpart VVa level of control" is within the preamble.

    EPA RESPONSE:
    We simply mean that the regulatory text in this proposed section, like the 2012 rule, will point to 40 CFR part 60 subpart VVa. In other words, the requirement is to comply with VVa as directed by the proposed regulatory text.

37. Page 279. Reviewer recommends providing additional discussion why EPA chose 4 months as the time that correction of any deficiencies need to be corrected.

    EPA RESPONSE:
    This section refers to a suggested structure of an audit program for fugitives. EPA is taking comment on all aspects of the proposal. "The Agency seeks comment as to whether this approach is appropriate for the type of auditing we describe below, or whether an alternative approach, such as requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols (e.g. American National Standards Institute (ANSI), ASTM International (ASTM), European Committee for Standardization (CEM), International Organization for Standardization (ISO), and National Institute of Standards and Technology (NIST) standards), would be preferable."

38. Page 293. Reviewer recommends clarifying whether the total annualized engineering costs provided include the benefits from recovered natural gas. If so, reviewer recommends providing both the costs with and without the benefits from recovered natural gas.

    EPA RESPONSE:
    We made this change in the preamble. Please see response above.

39. Page 301. Reviewer recommends providing citations to past regulatory analyses that have used GWP of $CH_4$ to convert emission impacts to $CO_2e$.

    EPA RESPONSE:
    Added citations to the text.

    "For example, see (1) U.S. EPA. (2012). "Regulatory impact analysis supporting the 2012 U.S. Environmental Protection Agency final new source performance standards and amendments to the national emission standards for hazardous air pollutants for the oil and natural gas industry."

Retrieved from http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf and (2) U.S. EPA. (2012). "Regulatory impact analysis: Final rulemaking for 2017–2025 light-duty vehicle greenhouse gas emission standards and corporate average fuel economy standards."

Retrieved from http://www.epa.gov/otaq/climate/documents/420r12016.pdf"

40. Page 304. Reviewer recommends providing additional information to Table 6 on what the "95th Percentile" relates to as it is unclear what this 95th percentile relates to.

    EPA RESPONSE:
    EPA has updated table note "a" on Table 6 to explain what the 95th percentile refers to.

41. Page 312. Reviewer recommends providing in Table 8 a discussion of the disbenefits from the proposed regulation, if they are not monetized, instead of within a footnote to the monetized benefits.

    EPA RESPONSE:
    Please see response above regarding our treatment of secondary $CO_2$ emissions in the RIA.

42. Page 374. Reviewer recommends clarifying whether annual surveys that detect emissions one time would return to semiannual surveys and why this difference exists.

    EPA RESPONSE:
    Please see clarifying text in section §60.5397a (i).

**Typographical Comments:**

1. Page 14. Reviewer recommends modifying the sentence to state:
    a. In addition, with respect to equipment used category-wide of which only a subset of those equipment are covered under the NSPS VOC standards (i.e., pneumatic controllers and compressors located other than at well sites), EPA's analysis shows that the BSER for reducing VOC from the remaining unregulated equipment to be the same as the BSER for those currently regulated.

    EPA RESPONSE:
    Correction made to the preamble.

2. Page 34-35. Reviewer recommends modifying the section to state:
    a. These actions encompass both **cost-effective** commonsense standards and cooperative engagement with states, tribes and industry. Building on prior actions



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by the Administration, and leadership in states and industry, the announcement laid out a plan for EPA to address, and if appropriate, propose and set commonsense standards for methane and ozone forming emissions from new and modified sources and issue new guidelines (CTG) to assist states in reducing ozone-forming pollutants from existing oil and gas systems in areas that do not meet the health-based standard for ozone.

EPA RESPONSE:
Added the CTG edits to the preamble.

3. Reviewer recommends ensuring consistency in the use of subscripts within $CO_2$ and $CH_4$ throughout the document.

   EPA RESPONSE:
   We will verify subscripts for consistency.

4. Reviewer recommends removing "or not" whenever "whether or not" is stated within the preamble.

   EPA RESPONSE:
   EPA will do a word search to determine where this may be appropriate without changing the intent of this package.

**Comment Moved from RIA Interagency Comments:**

1) First annual report is listed as being due January 15, 2014 – date has passed but no language indicates it will be changed. Most other places there is language inserted to identify the date will be changed or inserted as it becomes necessary.

   EPA RESPONSE:
   The first annual report date of January 15, 2014 was only provided as guidance in the 2013 final rule preamble. See 78 FR 58417. We have previously acknowledged that the date was calculated in error. The rule text at 60.5420(b) provides that the initial annual report will be due no later than 90 days after the end of the compliance period. This date will be January 13, 2014, or will be specific to the source based on their initial compliance period established under section 60.5410, if initial startup is after October 15, 2012.

## EPA RESPONSE TO

Summary of Interagency Working Comments on Draft Language under EO12866/13563 Interagency Review. Subject to Further Policy Review.

**Environmental Protection Agency (EPA): Proposed Rule**

**Oil and Natural Gas Sector: Emission Standards for New and Modified Sources**

**RIN 2060-AS30**

**General Comments:**

1. Reviewer recommends providing additional discussion on why it is necessary to regulate methane in the areas where controls for VOCs are already providing the reduction.

   EPA RESPONSE:
   We believe the preamble fully supports across the category regulation of VOC and methane. "Based on the EPA's analysis (see section VIII), we believe it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category, and that the best system of emission reduction (BSER) for methane for all these sources is the same as the BSER for VOC. Accordingly, the current VOC standards also reflect the BSER for methane reduction for the same emission sources. In addition, with respect to equipment used category-wide of which only a subset of those equipment are covered under the NSPS VOC standards (i.e., pneumatic controllers and compressors located other than at well sites), EPA's analysis shows that the BSER for reducing VOC from the remaining unregulated equipment to be the same as the BSER for those currently regulated. The EPA is therefore proposing to extend the current VOC standards for these equipment to the remaining unregulated equipment."

2. Reviewer recommends considering the overall economic impact on stripper wells and ensuring that any proposed NSPS requirements are not overly burdensome such that stripper wells would need to be shut down based on any single or combination of proposed requirements.

   EPA RESPONSE:
   Please see additional discussion in the preamble. "We do not intend to subject low production wells (i.e., those with an average daily production of 15 barrel equivalents or less) to the standards for well completion. It is our understanding that drilling of a low production well is infrequent and in most instances unintentional, but production may nevertheless proceed due to economic reasons. While we have learned that a daily average of 15 barrel equivalents is representative of low production wells, we solicit comment on the appropriateness of this threshold for applying the standards for well completions. We further solicit comment on the air emissions associated with low production wells, and the characteristics of low production wells that may inform owners or operators and enforcement personnel in advance of production whether such a well would be a low production well, so we may evaluate the feasibility of an exemption from well completion standards."



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Well Completions:

1. Reviewer recommends considering other factors such as geographic location, gas production and GOR of nearby wells, length of hydraulic fracturing, and well depth to sub-categorize units to maximize cost-effectiveness and not unduly burden units.

   EPA RESPONSE:
   We are taking comment on this in Section VIII.F "We solicit comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional)."

   Further, we are proposing a GOR threshold of 300 scf/barrel for applicability of well completion requirements. We understand that it is important for operators to know the affected facility status of a well completion prior to commencement of the completion operation and are soliciting comment whether GOR of nearby wells is a reliable indicator that could be used by operators.

2. Reviewer recommends not regulating oil wells for which gas recovers would be too small (e.g., yielding less than 30 tons).

   EPA RESPONSE:
   We are taking comment on this in Section VIII.F. Please see response to previous question. The purpose of the proposed GOR threshold is to identify and exclude wells that would have very small magnitudes of gas production and potential emissions.

3. Reviewer recommends considering the following thresholds:
   a. physical characteristics of certain oil wells that make REC and/or combustion not technically feasible or economic;
   b. all vertical oil wells as the nature of the wells make it difficult or technically infeasible to operate a two or three phase gas/liquid separator because these wells generally lack sufficient wellhead pressure or a sufficient quantity of gas; and/or
   c. low pressure or low volume wells and heavy oil wells based on the GOR. Low pressure wells could be based on a threshold sales line/gathering line or a wate gradient formula.

   EPA RESPONSE:
   We are taking comment on this in Section VIII.F.

Pneumatic Controllers:

1. Reviewer recommends removing any recordkeeping requirements for low-bleed or zero-bleed pneumatic controllers as it is unnecessary and burdensome.

EPA RESPONSE:
In locations other than natural gas processing plants, low-bleed and zero-bleed pneumatic controllers are not affected facilities, and thus no recordkeeping or reporting requirements apply to this equipment. However, natural gas-operated pneumatic controllers located at natural gas processing plants are affected facilities regardless of their bleed rate. In such cases, this equipment is subject to the recordkeeping and reporting requirements outlined in §60.5420a. Such records would include justification of the need for a device with a natural gas bleed rate greater than zero.

Compressors:

1. Reviewer recommends explaining how the National Inventory based on Subpart W data was considered within the development of the proposed rule. Specifically, as the more recent data appears to provide lower emission data, how has EPA taken that into consideration when developing the proposed rule?

   EPA RESPONSE:
   Detailed information on data used in the development of the proposed rule, and a discussion of data from alternative and newly available data sources, is included in the TSD.

   For most sources, emissions and activity data from the 2014 U.S. GHG Inventory (GHGI) were used in the development of the proposed rule. While overall sector-level emissions decreased in the 2015 GHGI compared to the 2014 GHGI (primarily due to revisions to offshore production estimates), emissions and activity data for the sources included in this proposal did not change significantly. The most recent facility-level GHGRP data was also reviewed in the development of the proposed rule. The GHGRP data indicate higher emissions than in the GHGI for some sources and indicate lower emissions for others, as is discussed in the TSD.

   As EPA continues to review new data sources, including key activity data from the GHGRP which will become available in the fall of 2015, EPA will consider how these data may be used to update its GHG inventory estimates and analyses related to this rulemaking. EPA has for several sources updated the GHGI to use GHGRP data and will continue to do so as additional key data become available.

2. Reviewer recommends removing the requirement for vapor recovery units for wet-seal centrifugal compressors as there are potential issues related to feasibility and safety.

   EPA RESPONSE:
   The proposed NSPS does not require vapor recovery units for control of emissions from wet-seal centrifugal compressors; the rule requires 95 percent control of these emissions or routing of the emissions to a process. Under section 111, the EPA cannot dictate what

type of control device is required to meet an emission standard. That decision is made by the owner or operator. The NSPS does include, however, requirements for specific types of control devices, if such devices are used to meet the emission standard (e.g., cover and closed vent system requirements and requirements for periodic monitoring). As is the case across the NSPS, a control technique is not considered BSER if technical feasibility or safety issues are a concern.

3. Reviewer recommends providing additional explanation how EPA ensured that emissions from rod packing leaks are separated from fugitive emissions from compressors.

   EPA RESPONSE:
   Fugitive emissions do not include gas that is vented from a device (e.g., pneumatic controller exhaust port, reciprocating compressor rod packing). As a result, fugitives seen in the rod packing area would likely not be from a fugitive emissions component since, given the structure of reciprocating compressors, it is unlikely to have valves, flanges, etc. located in the immediate area of the rod packing.

Pneumatic Pumps:

1. Reviewer recommends excluding diaphragm pumps, glycol pumps, and all low volume chemical injection pumps or other pumps that are used intermittently below a fixed number of hours/year.

   EPA RESPONSE:
   Glycol (i.e., "Kimray") pumps are not covered by the proposed NSPS. With regard to an operating hour threshold, we would need additional data (such as emissions levels associated with different operating times and costs) to fully evaluate this potential option.

Fugitive Emissions:

1. Reviewer recommends considering additional options besides OGI and Method 21, specifically AVO methods. The relative benefits and costs should be included within the discussion.

   EPA RESPONSE:
   We are requesting comment on whether there are other fugitive emission detection technologies that provide an equivalent or greater level of detection than OGI technology or EPA Method 21 that should be allowed in VIII.F.

2. Reviewer recommends providing clarification for the repair costs within the RIA and TSD for Method 21 and OGI. It is unclear why the repair costs change within OGI to the extent that they do and why they differ from Method 21.

EPA RESPONSE:
Please see clarification in section VIII.G, "While the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency". Section 5.4 of the TSD provides additional repair cost information.

3. Reviewer recommends providing clarification for why the emission reduction estimates deviate from the Colorado source document and how it was used within the RIA.

EPA RESPONSE:
The preamble states that information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of surveys performed and different assumptions made by the study authors. We used engineering judgment to identify anticipated percent reduction based on frequency. We believe that 40%, 60%, and 80% are adequately representative of the reduction we would expect with increased frequencies of survey.

4. Reviewer recommends providing additional information on the Method 21 emission reduction information. It is unclear within the TSD how the differences between the Method 21 for 10,000 ppm leaks and Method 21 for 5,000 ppm leaks were determined (see Table 5-20 on page 98).

EPA RESPONSE:
Please see clarifying text in Section VIII.G, and Section 5.4 of the TSD. "In our analysis, we estimated emissions reductions for annual, semiannual and quarterly options for conducting the Method 21 monitoring at the three repair threshold levels of 500 ppm, 2,500 ppm and 10,000 ppm. The EPA Equipment Leaks Protocol document provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry. This data was used to estimate the uncontrolled emissions (i.e., baseline emissions and the corresponding emission reduction percentages that could potentially be achieved for each of the leak definitions (500 ppm, 2,500 ppm, 10,000 ppm) and monitoring frequencies (annual, semiannual, quarterly). Using this information we calculated an expected emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold."

5. Reviewer recommends providing additional discussion on whether observed leak rate would change over successive surveys, and if so, account for that within the analysis.

EPA RESPONSE:
EPA will provide this additional context in the technical support document.

6. Reviewer recommends phasing in fugitive emissions requirements with larger sources in the first year and smaller sources in the following years. Small firs should also be

provided 180 days instead of 30 days after well completion.

EPA RESPONSE:
We are soliciting comment on whether 30 days is an appropriate period for the first survey following startup or modification.

7. Reviewer recommends co-proposing OGI and Method 21 as BSER or proposing Method 21 as BSER and allowing OGI as an acceptable compliance mechanism.

EPA RESPONSE:
Our BSER analysis is detailed in Section VIII.G, and OGI with semiannual monitoring remains BSER. However, we are taking comment on allowances for use of Method 21 in certain circumstances. "As explained above, Method 21 is not as cost-effective as OGI. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI, either for monitoring surveys or re-survey to assure proper repair. For example even though we envision repairs and resurveys to occur during the monitoring survey, there may be components that cannot be immediately repaired and require additional time for such repairs thus requiring the resurveying at a later time. In such situations, an owner and operator may prefer to use Method 21 for resurvey if it is readily available. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys and re-surveys."

8. Reviewer recommends not performing LDAR at well sites unless there are gathering lines or well head pressure greater than 150 psi. Reviewer also recommends EPA take comment on varying survey frequencies based on performance criteria.

EPA RESPONSE:
Although we agree that pressure can have an effect on occurrence and magnitude of some leaks causing fugitive emissions, we do not have information that would support a specific threshold. We also note that many fugitive emissions are related to flash emissions from storage vessels combined with undersized closed vent systems that are required to be designed to convey all emissions from the storage vessel to the control device. These emissions are independent of gathering line pressure.

**To:** Marten, Alex[Marten.Alex@epa.gov]
**From:** Gilbreath, Jan
**Sent:** Tue 8/4/2015 2:38:42 PM
**Subject:** FW: Email 1 of 2: EO12866 O&G 2060 AS30 Revised RIA and response to interagency comments
EO12866_O&GNSPS 2060 AS30 RIA_20150803_RLSO.docx
Summary of Interagency Comments under EO12866_E013563_Oil&Gas_NSPS_RIA 080315.DOCX
EO12866_O&GNSPS 2060 AS30 RIA Spreadsheet_20150803.xlsx
EO12866_O&GNSPS 2060 AS30 RIA_20150803_clean.docx

**From:** Hambrick, Amy
**Sent:** Monday, August 03, 2015 9:52 PM
**To:** Aaron_L_Szabo@omb.eop.gov
**Cc:** Gilbreath, Jan; Cozzie, David; Moore, Bruce; Macpherson, Alex; Thompson, Lisa; Hambrick, Amy; Spells, Charlene; Witosky, Matthew; Eck, Janet; Rush, Alan
**Subject:** Email 1 of 2: EO12866 O&G 2060 AS30 Revised RIA and response to interagency comments

Aaron,

Please see the attached revised RIA and EPA's response to the interagency comments.

The following documents are attached:

- Revised RIA RLSO
- Revised RIA clean
- Revised ROCIS spreadsheet
- Response to interagency comments

Thank you,

Amy

Amy Hambrick

U.S. Environmental Protection Agency

(919)541-0964

| Category | Estimates: Primary Estimate | Estimates: Low Estimate | Estimates: High Estimate | Units: Year Dollar | Units: Discount Rate | Units: Period Covered | Notes |
|---|---|---|---|---|---|---|---|
| **Benefits** | | | | | | | |
| Annualized Monetized ($billions/year) | 0.550 | 0.25 | 1.40 | 2012 | 7% | 2025 | The monetized benefits in this RIA include those from reducing methane emissions, which are valued using the social cost of methane (SC-CH4). The primary benefits estimate reflects the mean SC-CH4 at a 3% discount rate. The low and high estimates reflect mean SC-CH4 at a 2.5% discount rate and 95th percentile SC-CH4 at 3 percent, respectively. |
| | 0.550 | 0.25 | 1.40 | 2012 | 3% | 2025 | |
| Annualized Quantified | | | | | | | |
| Qualitative | Benefits from reduced direct exposure to SO2 and NO2, Hg and HCl | | | | | | |
| **Costs** | | | | | | | |
| Annualized Monetized ($billions/year) | 0.420 | | | 2012 | 7% | 2025 | The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate. |
| | 0.420 | | | 2012 | 3% | 2025 | |
| Annualized Quantified | | | | | 7% | | |
| | | | | | 3% | | |
| Qualitative | | | | | | | |
| **Transfers** | | | | | | | |
| Federal Annualized Monetized ($billions/year) | | | | | 7% | | |
| | | | | | 3% | | None estimated. |
| From/To | From: | | | To: | | | |
| Other Annualized Monetized ($billions/year) | | | | | 7% | | |
| | | | | | 3% | | None estimated. |
| From/To | From: | | | To: | | | |
| **Effects** | | | | | | | |
| State, Local, and/or Tribal Government | EPA has determined that this rule will not impose a federal mandate that may result in expenditures of $100 million or more for State, local or tribal governments. | | | | | | |
| Small Business | This rule is expected to have a significant impact on a substantial number of small entities. Therefore, a small business advocacy review panel was initiated. | | | | | | |
| Wages | No estimates available regarding changes in wages. | | | | | | |
| Growth | We do not have any estimates provided regarding changes in economic growth associated with implementation of this proposed rule. | | | | | | |

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| Category | Estimates: Primary Estimate | Estimates: Low Estimate | Estimates: High Estimate | Units: Year Dollar | Units: Discount Rate | Units: Period Covered | Notes |
|---|---|---|---|---|---|---|---|
| **Benefits** | | | | | | | |
| Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Annualized Quantified | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Qualitative | | | | | | | |
| **Costs** | | | | | | | |
| Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Annualized Quantified | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Qualitative | | | | | | | |
| **Transfers** | | | | | | | |
| Federal Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| From/To | From: | | | To: | | | |
| Other Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| From/To | From: | | | To: | | | |
| **Effects** | | | | | | | |
| State, Local, and/or Tribal Government | | | | | | | |
| Small Business | | | | | | | |
| Wages | | | | | | | |
| Growth | | | | | | | |

| Category | Estimates | | | Units | | | Notes |
|---|---|---|---|---|---|---|---|
| | Primary Estimate | Low Estimate | High Estimate | Year Dollar | Discount Rate | Period Covered | |
| **Benefits** | | | | | | | |
| Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Annualized Quantified | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Qualitative | | | | | | | |
| **Costs** | | | | | | | |
| Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Annualized Quantified | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Qualitative | | | | | | | |
| **Transfers** | | | | | | | |
| Federal Annualized Monetized ($millions/year) | 250.0 | 0.0 | 0.0 | 2005 | 7% | 2005 | |
| | 250.0 | 0.0 | 0.0 | 2005 | 3% | 2005 | |
| From/To | From: | Medicare | | To: | Home Health Agencies | | |
| Other Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| From/To | From: | | | To: | | | |
| **Effects** | | | | | | | |
| State, Local, and/or Tribal Government | N/A | | | | | | |
| Small Business | N/A | | | | | | |
| Wages | N/A | | | | | | |
| Growth | N/A | | | | | | |

| Category | Estimates: Primary Estimate | Estimates: Low Estimate | Estimates: High Estimate | Units: Year Dollar | Units: Discount Rate | Units: Period Covered | Notes |
|---|---|---|---|---|---|---|---|
| **Benefits** | | | | | | | |
| Annualized Monetized ($millions/year) | 60.3 | 51.2 | 69.3 | 2005 | 7% | 2005-2009 | |
| | 60.7 | 51.6 | 69.8 | 2005 | 3% | 2005-2009 | |
| Annualized Quantified | 88.9 | 80.0 | 97.7 | | 7% | | |
| | 91.1 | 82.0 | 100.2 | | 3% | | Reduction in deaths due to infection |
| Qualitative | Increased patient safety and increased provider flexibility | | | | | | |
| **Costs** | | | | | | | |
| Annualized Monetized ($millions/year) | 46.0 | 41.4 | 50.6 | 2005 | 7% | 2005-2009 | |
| | 44.8 | 40.4 | 49.3 | 2005 | 3% | 2005-2009 | |
| Annualized Quantified | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| Qualitative | | | | | | | |
| **Transfers** | | | | | | | |
| Federal Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| From/To | From: | | | To: | | | |
| Other Annualized Monetized ($millions/year) | 0.0 | 0.0 | 0.0 | | 7% | | |
| | 0.0 | 0.0 | 0.0 | | 3% | | |
| From/To | From: | | | To: | | | |
| **Effects** | | | | | | | |
| State, Local, and/or Tribal Government | N/A | | | | | | |
| Small Business | N/A | | | | | | |
| Wages | N/A | | | | | | |
| Growth | N/A | | | | | | |

**To:** Macpherson, Alex[Macpherson.Alex@epa.gov]
**Cc:** Marten, Alex[Marten.Alex@epa.gov]; Ferris, Ann[Ferris.Ann@epa.gov]
**From:** Evans, DavidA
**Sent:** Mon 8/3/2015 1:32:06 PM
**Subject:** RE: Two paper for d docket
bushnell et al 2015 w21259.pdf

Alex,

Here is the Bushnell et al paper. I'm working on Schenach (sp?) now. I need to copy and scan it.

Dave

**From:** Macpherson, Alex
**Sent:** Monday, August 03, 2015 7:37 AM
**To:** Evans, DavidA
**Cc:** Marten, Alex; Ferris, Ann
**Subject:** RE: Two paper for d docket

I'll try to get them in. If you get a chance, please check in with Ann if there are any papers cited in final that weren't at proposal, and see if we can get those in too.

Alex

**From:** Evans, DavidA
**Sent:** Sunday, August 02, 2015 9:58 PM
**To:** Macpherson, Alex
**Cc:** Marten, Alex
**Subject:** Two paper for d docket

Alex Mac.,

Hope these are still useful.

d

NBER WORKING PAPER SERIES

# STRATEGIC POLICY CHOICE IN STATE-LEVEL REGULATION: THE EPA'S CLEAN POWER PLAN

James B. Bushnell
Stephen P. Holland
Jonathan E. Hughes
Christopher R. Knittel

Working Paper 21259
http://www.nber.org/papers/w21259

NATIONAL BUREAU OF ECONOMIC RESEARCH
1050 Massachusetts Avenue
Cambridge, MA 02138
June 2015

The authors thank seminar participants at the Energy Institute at Haas, the Massachusetts Institute of Technology, the University of California at Berkeley and the University of North Carolina at Greensboro. The views expressed herein are those of the authors and do not necessarily reflect the views of the National Bureau of Economic Research. Bushnell's work was supported in part by the National Science Foundation under award 1229008. Bushnell serves on the Market Surveillance Committee to the California Independent System Operator (CAISO). The MSC is an independent advisory committee to the CAISO's Board of Governors.

At least one co-author has disclosed a financial relationship of potential relevance for this research. Further information is available online at http://www.nber.org/papers/w21259.ack

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Strategic Policy Choice in State-Level Regulation: The EPA's Clean Power Plan
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**ABSTRACT**

Flexibility in environmental regulations can lead to reduced costs if it allows additional abatement from lower cost sources or if policy tailoring and experimentation across states increases regulatory efficiency. The EPA's 2014 Clean Power Plan, which implements greenhouse gas regulation of power plants under the Clean Air Act, allows substantial regulatory flexibility. The Clean Power Plan sets state-level 2030 goals for emissions rates (in lbs CO2 per MWh) with substantial variation in the goals across states. The Clean Power Plan allows states considerable flexibility in attaining these goals. In particular, states can choose whether to implement the rate standards goals or equivalent mass-based goals (i.e., emissions cap and trade, CAT). Moreover, states can choose whether or not to join with other states in implementing their goals. We analyze incentives to adopt inefficient rate standards versus efficient CAT standards using both analytical and simulation models. We have five main results. First, we theoretically show that industry supply can be efficient under both CAT regulation and rate-based regulation. However, under rate-based standards the carbon price must equal the social cost of carbon and the rate standard must be equal across all the states. Second, we illustrate important differences in the incentives of a unified coalition of states and the incentives of a single state. Third, our simulation results show that when states fail to coordinate on a policy, the merit order can be ``scrambled'' quite dramatically leading to significant inefficiencies. Fourth, the Nash equilibrium of a game between coastal and inland western states is an inefficient policy for consumers and an uncoordinated policy for generators. Finally, we show that how new plants are treated under the Clean Power Plan has large effects on the scale and location of entry.

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# 1 Introduction

Within the United States, state-by-state variation in regulatory approaches has been more of the norm than an exception. Within the utility industries, individual state regulatory commissions have used substantially different variations on the rate-of-return regulatory framework, for example, while some states have chosen to rely on wholesale power markets instead of vertically integrated utilities. In the environmental realm, the Federal Environmental Protection Agency (EPA) has often deferred to state or local air quality regulators to develop specific implementation plans to achieve the EPA's environmental mandates. The Clean Air Act, one of the dominant environmental regulatory instruments, requires the EPA to leave regulatory decisions up to individual states.

In electricity markets, the regulatory actions of states, or even local communities, often affect the market outcomes in surrounding areas because electricity flows throughout regional networks. In the climate change policy arena, California and states in the northeastern U.S. have faced this issue with their unilateral adoption of cap-and-trade programs limiting carbon emissions from in-state sources. In both instances, there have been concerns that such actions could spur "leakage" of both emissions and of beneficial economic activity to the neighboring uncapped regions; specifically, while emissions may decrease within the regulatory jurisdictions, emissions may *increase* elsewhere as output increases from unregulated power plants.[1]

A more subtle form of economic spillovers can arise when individual states respond to regulatory requirements with different instruments. The choice of instrument affects each power plant's opportunity cost of selling electricity. Therefore, certain policies may provide a competitive advantage to power plants within a particular state, and this advantage will depend on the policies adopted in other states. In the face of these incentives, it is not clear the equilibrium outcome will yield the efficient mix of policies.

Recent actions by the EPA to address greenhouse gas emissions create a similar dynamic. In this case however, the stakes are much higher than the examples above. The EPA's "Clean Power Plan" (CPP) proposes major reductions in carbon emissions from electricity generators in the United States (US). Focusing on the electricity sector, the CPP uses existing provisions of the Clean Air Act Amendments to regulate a substantial share of carbon emissions. Due in part to inaction at the federal level, recent US climate policy has been driven almost exclusively by state and regional initiatives. This has raised concerns over inefficiencies from uncoordinated policies (Bushnell, Peterman and Wolfram (2008)). A national

[1] See Fowlie (2009) and Chen (2009).

framework holds the potential to decrease inefficiencies created by the patchwork of state and regional policies and could improve US standing in international climate negotiations (Newell, Pizer and Raimi (2012), Stavins (2008)).

The regulatory approach taken by the EPA is, in many ways, unprecedented. The CPP establishes state-level targets for carbon emissions *rates* in lbs of carbon dioxide per megawatt hour of electricity generated (lbs per MWh). States have a great deal of flexibility in how to achieve these goals. For example, they may adopt the default rate standard or they could adopt an equivalent "mass-based" regulation such as a carbon cap and trade system (CAT). Under a rate standard, the state must decrease its carbon emissions rate, whereas under a mass-based standard the state must decrease its aggregate emissions (e.g., create an emissions cap). Because these systems create different incentives, effects on consumers and producers within a state could be quite different depending on the type of regulation adopted. Because electricity is traded regionally across state lines, these effects depend on both the type of regulation adopted by each state as well as regulations adopted by its trading partners. Furthermore, the states' private incentives may be at odds with those of a national social planner.

We analyze the potential effects of the CPP in terms of electricity market outcomes and state adoption incentives. We first analyze a general theoretical model and then calibrate a simulation model to analyze electricity markets in the western United States.

We have five main results. First, we theoretically show that industry supply, i.e., the merit order, can be efficient under both CAT regulation and rate-based regulation. However, under rate-based standards the carbon price must equal the social cost of carbon *and* the rate standard must be equal across all the states. Importantly, if carbon prices are equal across states but rate standards are not equal, carbon costs would be different for identical generators in the different states and thus the merit order could be inefficient. Efficiency of supply is a necessary but not sufficient condition for efficiency. In fact, if demand is not perfectly inelastic, we show that only CAT can be efficient. This result echoes earlier results in the literature, e.g., Helfand (1991), Holland, Hughes and Knittel (2009).

Second, we illustrate important differences in the incentives of a unified coalition of states and the incentives of a single state. For the coalition of states, adoption of CAT is best from an efficiency perspective. However, from the perspective of an individual state, adoption of a rate standard (instead of CAT) results in lower electricity prices. This benefits consumers (both in this state and in other states) so consumers have an incentive to lobby for adoption of rate standards. From a generator's perspective, lower electricity prices from adoption of a rate standard could lead to lower profits. However, regulated generators' costs fall by more than the electricity prices fall. This leads to a split in incentives for generators. Generators whose operations are not covered by the regulation, e.g., distributed generation, renewables, nuclear, small fossil plants, prefer the high electricity prices associated with CAT. On the other hand, regulated generators (e.g., existing fossil plants) benefit from lower costs and prefer rate standards. Holding carbon prices fixed, we show adoption of a rate standard is a dominant strategy from the perspective of "covered" generators, but adoption of CAT is a dominant strategy from the perspective of "uncovered" generators.

We explore our theoretical predictions using a simulation model for the eleven states in the western interconnection of the U.S. electricity grid simulating a variety of regulation scenarios including: no regulation (business as usual, BAU), a single West-wide CAT standard, a single West-wide rate standard, state-by-state CAT standards, and state-by-state rate standards. We also simulate mixed CAT and rate standards across two coalitions: the Coastal states (CA, OR, and WA) and the Inland states (AZ, CO, ID, MT, NM, NV, UT, and WY). We update the model with current natural gas prices and test the sensitivity of our results to this assumption.

This leads to our third main finding: when states fail to coordinate on a policy, the merit order can be "scrambled" quite dramatically leading to significant inefficiencies. In particular, state-by-state CAT or rate standards result in full-marginal costs (and a merit order) which are substantially different than would result under a west-wide policy. We show the merit order is further distorted when coalitions of states adopt different policies. To estimate welfare effects of the different policies, we first calculate the short-run equilibria under the different scenarios. We analyze changes in consumer surplus, generator profits, carbon market revenue, and calculate the deadweight loss of each scenario based on an estimate of the social cost of carbon. We assume the carbon price under a West-wide CAT equals the social cost of carbon and therefore produces no deadweight loss. Under business as usual, deadweight loss is approximately $0.69 billion per year.

The deadweight loss from adopting a West-wide rate standard is about 30% of the BAU deadweight loss. This is due to electricity prices that are too low relative to the first best resulting in too much consumption of electricity. This lower electricity price implies higher consumer surplus under a rate standard. Perhaps more importantly, our short-run analysis also shows substantial deadweight loss from a failure to coordinate policies. In particular, state-by-state rate standards result in a deadweight loss which is twice that of business as usual, i.e., which is twice as bad as doing nothing. In contrast, the deadweight loss from failures to coordinate on CAT standards is only 30% of the BAU deadweight loss.

Fourth, we analyze the incentives to form regional trading markets. We consider the



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incentives of the two blocks of states defined above: Coastal and Inland states. Our calculations show that from an abatement cost perspective (the sum of consumer surplus, generator surplus, and any carbon market revenue) the strategic interaction between the regions would result in west-wide adoption of CAT, i.e., CAT/CAT is the "Nash equilibrium". When we look at the individual sets of stakeholders, CAT/CAT is no longer an equilibrium. From a consumer's perspective, the Nash equilibrium would be Rate/Rate, i.e., would result in west-wide adoption of a rate standard. The incentives of firms depend on the mix of covered and uncovered generators. From the generator's perspective, we find there is a strong incentive to have different regulatory mechanisms; Cap/Rate and Rate/Cap are both Nash equilibria.

Finally, we analyze investment decisions. At the time of this writing, the extent to which state-level plans may or may not include new plants under their Clean Power Plan compliance strategies has not been resolved. Section 111(d) of the Clean Air Act covers only existing sources. New sources are regulated separately and will have to comply with a source-specific $CO_2$ emissions rate standard. We analyze investment in new combined-cycle gas turbines under an assumption of 10% demand growth relative to 2007. Under a CAT system, abatement levels are dramatically lower when new investments are excluded. Under a rate standard, abatement levels are higher when new investments are excluded. Average abatement costs are generally higher when new plants are excluded under CAT. The location of new investment will also depend on the regulatory mix. In general new investment will occur in the rate-standard regions if it is included under the Clean Power Plan, since $CO_2$ emissions from a combined-cycle gas turbine are below the Clean Power Plan standard. Our calculations show that investment swings can be quite dramatic for different changes in the regulatory mix.

This work contributes to the literature on environmental and economic spillovers from local climate policies. The fact that GHG policy has been driven at the local, rather than national level, has long created concern over the geographic limitations of the regulations. Three concerns exist. First, as noted environmental targets can be undermined if production is able to shift away from the jurisdictional reach of the regulator through either leakage or reshuffling of production sources.[2] Second, the existence of many local regulatory programs is unlikely to lead to the efficient amount of abatement across the regions as marginal abatement costs will not equalize. Third, regulatory action in one area may put firms in that region at a competitive disadvantage relative to firms in unregulated regions. These concerns have been a challenge for regional climate initiatives in the US. More generally, concerns over leakage have been a challenge for international climate agreements. In the crafting of European

[2]See Bushnell, Peterman and Wolfram (2008), Fowlie (2009), and Chen (2009).



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$CO_2$ market, as well as the now defunct Waxman-Markey bill that would have established a national cap in the United States, much attention has been paid to the "competitiveness" question, which is fundamentally related to how vulnerable domestic producers are to leakage from imports.

Our theoretical model is most closely related to Fischer (2003). Fischer analyzes carbon trading between CAT and rate standards and finds that such trade raises carbon emissions. Our theoretical work extends the work of Fischer by analyzing two components which are necessary for understanding the CPP. First, we explicitly model trading in the product market (electricity) which crucially affects the interactions of the states' policy choices. Second, we analyze the states' adoption incentives for CAT and rate standards. Burtraw, et al. (Burtraw et al., 2015) also simulate electricity system outcomes under the CPP. They show that the choice of allocation policy can mitigate some of the perverse effects of inconsistent state regulatory choices. As we show here, however, states may not find it in their interest to mitigate those effects.

Finally, our work contributes to the literature on rate-based environmental regulation. Holland, Hughes and Knittel (2009) show a rate standard cannot, in general, achieve the efficient allocation of emissions and energy production.[3] In the case of a national low carbon fuel standard (LCFS) for transportation fuels, Holland, Hughes and Knittel (2009) and Holland et al. (Forthcoming) find the inefficiency is quite large. Average abatement costs are several times greater under an LCFS compared with a CAT system that achieves the same emissions reduction. We make three main contributions to this literature. First, prior work assumes demand for energy is essentially static. Since electricity demand can vary substantially hour to hour, our work explicitly captures time varying demand. Importantly, because different generators are dispatched in different periods depending on demand, mixed regulation may introduce inefficiencies by distorting the merit order. Second, we quantify the efficiency cost of rate standards compared to CAT policies in the electricity sector. While prior theory results imply rate standards are inefficient, we use our calibrated simulation model to estimate the magnitude of these effects. Third, we investigate states' unilateral incentives to adopt rate standards or CAT regulations. Since the EPA rule allows states to choose which system to adopt, understanding these incentives has important policy implications.[4]

Section 2 discusses the Clean Power Plan in more detail and provides policy background. Section 3 develops the theoretical model and derives the theoretical results. Section 4

[3] This inefficiency does not arise when rates are calculated using an exogenous base such as historical emissions (Holland, Hughes and Knittel, 2009) or GDP (Pizer, 2005).

[4] See also Holland (2012), Huang et al. (2013), Pizer (2005) and Zilberman et al. (2013).



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presents the simulation model and Section 5 describes the results. Section 6 concludes.

## 2 The Clean Power Plan: GHG Regulation under the Clean Air Act

Since the landmark 2007 decision by the U.S. Supreme Court in *Massachusetts v. EPA*, the EPA has taken several steps to limit GHG emissions under the Clean Air Act (CAA). One significant milestone occurred on June 2, 2014 when the Obama administration released the Clean Power Plan (CPP) proposing to regulate GHG emissions from existing power plants. Rather than following the usual permitting process, the CPP instead uses provisions in Section 111 of the CAA. Section 111 provides a flexible framework for regulation, but also imposes constraints on the types of policies that may be implemented under the CPP.

Regulation under Section 111 requires that the EPA establish "standards of performance" which are defined as as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction." The text also requires state-level implementation of the standards.

The Clean Power Plan implements Section 111 by establishing emissions rates (in lbs $CO_2$ per MWh) for each state.[5] These goals are constructed based on the estimated "best system of emissions reductions" for each state. The states then develop plans for achieving those goals, and the EPA approves the plans.

To estimate the best system of emissions reductions goals for each state, the Clean Power Plan uses four "building blocks" each of which contributes to emissions reductions. The first building block focuses on emissions from coal-fired generation. The second building block focuses on shifting generation from relatively dirty coal-fired plants to relatively cleaner gas-fired plants. The third building block requires increased generation from low emissions or zero-emissions generation (e.g., nuclear and renewables). The final (fourth) building block focuses on energy efficiency improvements. Efficiency improvements are treated as equivalent to zero-emissions generation, thus both the third and fourth building blocks reduce the goal's emissions rate by increasing the denominator of the "lbs $CO_2$ per MWh" goal.

[5] It is unclear why the CPP specifies rate standards (i.e., in lbs $CO_2$ per MWh) instead of mass-based goals (i.e., in lbs $CO_2$). The rationale is likely that rate standards are synonymous with performance goals as required in Section 111. Comments to the EPA recommend that the CPP publish equivalent mass-based goals for each state.



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Each state's emissions reductions goal from the four building blocks was published by the EPA for 2030 with an interim goal for 2020. The goals range across states from less than a 20% reduction in the emissions rate for North Dakota to over a 70% reduction in the emissions rate for Washington (see NRDC Summary of EPA's Clean Power Plan). The percent emissions reductions from Building Block 2 (the largest building block) are illustrated in Figure A.1. It is hard to compare the stringency of these different goals across states without knowledge of the marginal abatement cost curves across states. Nonetheless, it is clear that there is substantial variation in goals across states.

The CPP allows states to meet their goals by adopting either a "rate-based standard" or a "mass-based standard," i.e., a cap-and-trade (CAT) policy. The CPP also allows states to join a regional multi-state plan.[6] However, the CPP neither compels states to adopt a CAT nor compels states to follow a regional approach. This flexibility could allow states to tailor their regulations to better fit their unique circumstances. Alternatively, the flexibility could lead states to adopt inefficient regulations which benefit some stakeholders at the expense of others and lead to significant impacts in other states.

# 3 The model

Consider a model of electricity generation and consumption in multiple states (regions). Let $s$ index the states. Since electricity cannot be economically stored, prices vary across time if demand varies. Let $t$ index hours and assume electricity flows freely across the states so that the electricity price in hour $t$ is $p_t$ and is common across all the states.[7] Total demand at time $t$ is given by $D_t(p_t)$, and (net) consumer surplus, $CS$, is found by integrating under the demand curve and summing over $t$.[8]

Supply in the model comes from a variety of generating units each with a constant marginal cost of generation and a limited capacity. Since the generating units may be regulated differently across states, we differentiate generating units by their location. Let $i$ index the technologies (e.g., coal-fired, combustion turbine, etc.) and $s$ index the states.

[6] The CPP states: "A state could adopt the rate-based form of the goal established by the EPA or an equivalent mass-based form of the goal. A multi-state approach incorporating either a rate- or mass-based goal would also be approvable based upon a demonstration that the state's plan would achieve the equivalent in stringency, including compliance timing, to the state-specific rate-based goal set by the EPA."

[7] In the simulations, we extend the model to include transmission constraints.

[8] To analyze the distribution of consumer surplus, $CS_s$, across the states, we assume that each state's share of demand is a constant fraction of total demand.



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Assume $c_i$ is the marginal cost of generating from technology $i$; $\overline{q}_{si}$ is the installed capacity in state $s$ of technology $i$; and $\square_i$ is the carbon emissions rate of technology $i$.

Under a market-based carbon regulation, costs also include carbon costs. Let  be the social cost of carbon, and let $r \in \{BAU, CAT, RS\}$ index the carbon regulations: "business as usual," "cap-and-trade," and "rate standards."[9,10]

Define the *full marginal cost*, $FMC^r_{si}$, as the sum of the marginal generation plus (private) carbon costs. Below we define the full marginal cost for CAT and rate standards. In the absence of carbon regulation, i.e.., in BAU, private carbon costs are zero and $FMC^{BAU}_{si} = c_i$. We also define the *full marginal social cost* as the marginal generation plus social carbon costs, i.e., $c_i + \square_i$ .[11] Welfare, $W^r$, under regulation $r$ is defined as the gross consumer surplus less full social costs, or, equivalently, the sum of net consumer surplus, generator profit, and any carbon market revenue minus carbon damages.

The supply from each technology is determined by comparing the electricity price with the full marginal cost. Generators supply at capacity if the electricity price exceeds their full marginal cost, supply nothing if the price is below their full marginal cost, and supply any amount up to capacity if the price equals their full marginal cost.

The market supply is determined by aggregating the supply from each generation technology. The resulting market supply is a non-decreasing step function which orders the technologies by their full marginal cost. The order of the technologies along the supply curve determines the order in which generation units would be called into service as demand increases and is called the *merit order*.

The equilibrium electricity price in hour $t$ is found from the intersection of hour $t$ demand and market supply. Specifically, under carbon regulation $r$, the price in hour $t$ is given by:

$$p^r_t = \min\{p : D_t(p) \leq \sum_s \sum_i \square(FMC^r_{si} \leq p)\overline{q}_{si}\}, \tag{1}$$

where $\square$ is an indicator function which takes the value one if the argument is true and zero otherwise. Thus $\square(FMC^r_{si} \leq p)$ is one if $FMC^r_{si} \leq p$, i.e., if technology $i$ is willing to supply at price $p$ and is zero otherwise. The set defined in Eq. 1 is the set of prices for which there is excess supply. The minimum of this set will either be a price at which demand exactly

[9] The CPP defines "rate-based standards" and "mass-based standards". We simply refer to "rate standards" and "CAT" throughout.

[10] Below we define additional regulatory environments, e.g., CATx refers to a state with a CAT when other states may have rate standards.

[11] The full marginal social cost does not depend on the state or the carbon regulation.

equals market supply when all inframarginal generators supply at capacity (i.e., on a vertical portion of the supply curve) or will be a price at which any smaller price would have excess demand (i.e., on a horizontal portion of the supply curve).

Based on these equilibrium prices, we can now characterize the equilibrium generation and profits of each technology. If $q^r_{sit}$ is equilibrium generation in state s from technology i in hour t under regulation r, then profits are defined as $\pi^r_{si} \equiv \sum_t (p^r_t - FMC^r_{si}) q^r_{sit}$ for technology i in state s under carbon regulation r.[12] Finally, we define equilibrium carbon emissions as $Carbon^r = \sum_s \sum_i \sum_t \epsilon_i q^r_{sit}$.

## 3.1 Cap-and-trade (CAT) regulation

We now turn to equilibrium under a cap-and-trade (CAT) regulation limiting total carbon emissions. Let $E_s$ be allowable emissions in state s and $p_{cs}$ be the price of tradeable certificates for one unit of carbon emissions in state s. It is well known that such a cap-and-trade program raises costs of generators in proportion to their carbon emissions, and thus the full marginal cost of technology i is $FMC^{CAT}_{si} = c_i + \epsilon_i p_{cs}$ in state s.

These full marginal costs are illustrated in panel (a) of Fig. 1. The figure shows the marginal costs of four technologies: nuclear ($c_N$), coal ($c_C$), gas ($c_G$), and oil ($c_O$). As illustrated, the unregulated merit order would be first nuclear, then coal, gas, and finally oil because $c_N < c_C < c_G < c_O$. If the emissions rates are such that $\epsilon_O > \epsilon_C > \epsilon_G > \epsilon_N = 0$, the carbon regulation increases the full marginal costs of coal-fired generation more than of gas-fired generation due to coal's higher carbon emissions. Thus as illustrated the CAT regulation switches the merit order of coal- and gas-fired generation. Market supply would be found from Fig. 1 by re-ordering the technologies according to their full marginal costs.

If all states adopt CAT regulations, the equilibrium electricity price in hour t is characterized by Eq. 1 with this full marginal cost. Generator profits are given by $\pi^{CAT}_{si} \equiv$

[12] Technically, we define:

$$q^r_{sit} = \begin{cases} \bar{q}_{si}, & \text{if } FMC^r_{si} < p^r_t, \\ \bar{q}_{si}\alpha^r_{sit} & \text{if } FMC^r_{si} = p^r_t, \\ 0 & \text{if } FMC^r_{si} > p^r_t. \end{cases}$$

The equilibrium supply has three cases. If price is above marginal cost, then generation is at capacity. If price is below marginal cost, then generation is zero. If price is equal to marginal cost, we assume that each generator supplies the same fraction of their capacity $\alpha^r_{sit}$, where $0 < \alpha^R_{sit} < 1$. We define $\alpha^r_{sit} = \frac{D(p^R_t) - \sum_s \sum_i 1(FMC^r_{si} < p^r_t - \varrho)\bar{q}_{si}}{\sum_s \sum_i (1(FMC^r_{si} < p^r_t + \varrho) - 1(FMC^r_{si} < p^r_t - \varrho))\bar{q}_{si}}$, where $\varrho$ is small. Note that $\sum_s \sum_i (1(FMC^r_{si} < p^r_t + \varrho) - 1(FMC^r_{si} < p^r_t - \varrho)) \bar{q}_{si}$ is the additional capacity which becomes inframarginal when the price increases from $p^r_t - \varrho$ to $p^r_t + \varrho$. Only the portion $D(p^r_t) - \sum_s \sum_i 1(FMC^r_{si} < p^r_t - \varrho)\bar{q}_{si}$ of this additional capacity is required. So we assume that each technology on the margin supplies the same proportion of this additional generation. With a carbon policy $\alpha^r_{sit}$ may need to be redefined such that the carbon market clears.



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$\sum_t (p_t^{CAT} - MC_{si}^{CAT}) q_{sit}^{CAT} = \sum_t (p_t^{CAT} - c_i - \gamma_i p_{cs}) q_{sit}^{CAT}$. Thus generator profits do not include carbon market revenue, e.g., permits are auctioned not grandfathered, and welfare calculations must account for the carbon market revenue separately.

To complete the characterization of the CAT equilibrium, we describe equilibrium in the market for carbon certificates. Since the supply of permits is fixed at $E_s$, demand equals supply in state s when $\sum_i \sum_t \gamma_i q_{sit}^{CAT} = E_s$. Note that a higher carbon price $p_{cs}$ decreases carbon emissions, so there exists a carbon price which clears the carbon market.

The above characterization of the market equilibrium under CAT assumes each state has its own independent regulation. The model is readily extended to allow carbon trading between states. If states s and s′ allow carbon trading, then the price of carbon certificates is equal across both states, i.e., $p_{cs} = p_{cs'}$, and the market equilibrium is characterized by $\sum_i \sum_t \gamma_i q_{sit}^{CAT} + \sum_i \sum_t \gamma_i q_{s'it}^{CAT} = E_s + E_{s'}$. It is well known that allowing trading across cap-and-trade programs reduces the cost of achieving the aggregate emissions target. Note that the equilibrium is invariant to the distribution of the cap across the states, i.e., only the aggregate cap is relevant.

## 3.2 Rate standard regulation

Next we characterize equilibrium under a rate standard. A rate standard limits the aggregate carbon emissions per MWh of electricity and can be tradeable (see Holland, Hughes and Knittel (2009)). Let $\rho_s$ be allowed emissions per MWh in state s. Any technology whose emissions rate, $\gamma_i$, exceeds the standard would be required to purchase certificates per MWh based on the amount by which its emissions rate exceeds the standard. Conversely, any technology whose emissions rate is below the standard could sell certificates based on the difference between their emissions rate and the standard. Let $p_{cs}$ be the price of tradeable certificates for one unit of carbon emissions. Thus the rate standard changes the full marginal cost of generators based on whether they are buying or selling permits. In particular, the rate standard changes the full marginal cost of technology i in state s from $c_i$ to $c_i + (\gamma_i - \rho_s)p_{cs}$. Note that full marginal costs may be higher or lower than BAU depending on whether $\gamma_i - \rho_s$ is positive or negative, i.e., depending on whether a technology buys or sells certificates.

These full marginal costs are illustrated in panel (b) of Fig. 1 for the four technologies. As illustrated, the rate standard reduces the full marginal costs of (i.e., subsidizes) nuclear- and gas-fired generation, but increases the full marginal costs of coal- and oil-fired generation. As with the CAT, the merit order under rate standards as illustrated switches gas and coal, i.e., gas-fired generation is used before coal-fired generation as demand increases.



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If all states adopt rate standards, the equilibrium electricity price in hour t is characterized by Eq. 1 with these full marginal costs. Profits are $\Pi^{RS}_{si} = \sum_t (p^{RS}_t - MC^{RS}_{si})q^{RS}_{sit} = \sum_t (p^{RS}_t - c_i - (\square_i - \leftarrow_s)p_{cs})q^{RS}_{sit}$. As above we assume that generators are not given permits. However some generators create permits by generating electricity, namely, those relatively clean technologies for which $\square_i < \leftarrow_s$. In this case, the term $-(\square_i - \leftarrow_s)$ is positive and captures the revenue which would arise from selling carbon credits. Thus the profits capture all revenue streams and there is no carbon market revenue to be accounted for separately.

To complete the characterization of the equilibrium, we describe the market for carbon certificates. The demand for carbon certificates is determined by the amount each technology exceeds the standard and by how much electricity is generated from each technology. For example, demand for certificates in state s from technology i is $\sum_t (\square_i - \leftarrow_s)q^{RS}_{sit}$ if $\square_i > \leftarrow_s$. Similarly, supply in state s from technology i is $\sum_t (\leftarrow_s - \square_i)q^{RS}_{sit}$ if $\square_i < \leftarrow_s$. Because demand less supply equals zero in equilibrium, the carbon market equilibrium is characterized by $\sum_i \sum_t (\square_i - \leftarrow_s)q^{RS}_{sit} = 0$. Note that a higher carbon price $p_{cs}$ decreases demand and increases supply for carbon certificates, so there exists a carbon price which clears the carbon market. Note also that the equilibrium condition can be written

$$\frac{\sum_i \sum_t \square_i q^{RS}_{sit}}{\sum_i \sum_t q^{RS}_{sit}} = \leftarrow_s,$$

which implies that the aggregate carbon emissions rate exactly equals the rate standard in equilibrium.

The model can be readily extended to analyze two states who combine their rate standards through carbon trading. Suppose the states s and $s'$ allow carbon certificates to be freely traded between the states. Then the prices of the certificates are equal, i.e., $p_{cs} = p_{cs'}$, and the equilibrium condition is that demand across both states equals supply across both states. Setting demand less supply equal to zero, we can characterize the carbon market equilibrium by $\sum_i \sum_t (\square_i - \leftarrow_s)q^{RS}_{sit} + \sum_i \sum_t (\square_i - \leftarrow_{s'})q^{RS}_{s'it} = 0$. This equilibrium condition can be written:

$$\frac{\sum_i \sum_t \square_i (q^{RS}_{sit} + q^{RS}_{s'it})}{\sum_i \sum_t (q^{RS}_{sit} + q^{RS}_{s'it})} = \frac{\sum_i \sum_t q^{RS}_{sit}}{\sum_i \sum_t (q^{RS}_{sit} + q^{RS}_{s'it})}\leftarrow_s + \frac{\sum_i \sum_t q^{RS}_{s'it}}{\sum_i \sum_t (q^{RS}_{sit} + q^{RS}_{s'it})}\leftarrow_{s'}, \quad (2)$$

which implies that the aggregate carbon emissions rate equals a weighted average of the allowed emissions rates across the states where the weights depend on generation.

In addition to trading carbon, which equates the carbon prices, states may also wish to harmonize their rate standards, i.e., to set $\leftarrow_s = \leftarrow_{s'}$. Note that if states do *not* harmonize their rate standards, then the full marginal costs of identical generators can be different across states even if carbon prices are the same. In order to avoid this additional inefficiency, states would need to harmonize their rate standards as well as to allow carbon trading.

Combining rate standards across states does not have the efficiency justification of combining CAT regulations. Combining CATs across states allows the same aggregate emissions target to be attained at lower cost. Combining rate standards across states does reduce costs, but it also means that the emissions target changes: both the aggregate emissions and the aggregate emissions rate are changed by combining rate standards in two states.

## 3.3 Mixed CATs and rate regulation

Finally, we consider the case of *mixed regulation* in which some states adopt CATs and other states adopt rate standards. Under the Clean Power Plan proposals, states can choose what type of regulation to adopt and a mixture of CATs and rate standards could result. The model is readily extended to mixed regulation. In particular, the equilibrium electricity price is found from the set defined in Eq. 1 where the full marginal costs are $c_i + \square_i p_{cs}$ in a CAT state and $c_i + (\square_i - \leftarrow_s) p_{cs}$ in a rate standard state.

States could allow carbon trading across CATs and rate standards. If state s has a CAT and state $s'$ has a rate standard, then trading carbon certificates would equate the price of certificates in each state, i.e., would set $p_{cs} = p_{cs'}$. Setting the difference between aggregate certificate demand and supply equal to zero implies that the equilibrium certificate price is characterized by $\sum_i \sum_t \square_i q^{RS}_{sit} - E_s + \sum_i \sum_t (\square_i - \leftarrow_{s'}) q^{RS}_{s'it} = 0$. This condition does not have a clear interpretation either as a cap or a emissions rate constraint.

## 3.4 Theoretical results

We next compare the outcomes and adoption incentives under certain conditions for the general model. The proofs of all the results are in the appendix. Section 4 then quantifies the effects and makes additional comparisons with a simulation model in the context of the emissions reductions required under the CPP.

The first result describes conditions under which *supply* is efficient under the different regulations. We then address efficiency in a corollary.

Result 1. Efficient Supply: *The merit order is efficient (full social costs are minimized):*

*(i): if all states adopt CATs and* $p_{cs}$ *is sufficiently close to for all* s;



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(ii): *if all states adopt rate standards,* $p_{cs}$ *is sufficiently close to for all* s, *and* $\leftarrow_s$ *is sufficiently close to* $\leftarrow$ *for all* s*; or*

(iii): *if there is mixed regulation,* $p_{cs}$ *is sufficiently close to for all* s, $\leftarrow_s$ *is sufficiently close to* $\leftarrow$ *for all* s, *and* $|c_i + \square_i \; - c_j - \square_j \;| > \leftarrow$ *for all* i *and* j.

This result shows sufficient conditions for the efficiency of supply. Importantly, the sufficient conditions become increasingly stringent across the regulations. For CATs, supply is efficient if the carbon price equals (or is close to) the social cost of carbon.

For rate standards, supply can also be efficient. For a given carbon price, the CAT and rate standard induce the same merit order since $c_i + (\square_i - \leftarrow_s)p_{cs} < c_{i'} + (\square_{i'} - \leftarrow_s)p_{cs}$ if and only if $c_i + \square_i p_{cs} < c_{i'} + \square_{i'} p_{cs}$ Intuitively, the rate standard can induce the correct relative prices across the technologies because it simply shifts the full marginal costs down by a constant. However, supply efficiency for a rate standard requires that carbon prices equal the social cost of carbon *and* that the rate standards be equal across states. Note that these sufficient conditions will not be ensured by carbon trading alone but would also require explicit harmonization of the rate standards across states. Thus the sufficient conditions are more strict for rate standards than for CAT.

Surprisingly, Result 1 (iii) shows that mixed regulation can also attain the efficient supply but only under more stringent conditions. This result is illustrated in panel (c) of Fig. 1 for four technologies where some of each technology is subject to a CAT and some is subject to a rate standard of $\leftarrow$ and the carbon price is . Note that within each technology, the implicit subsidy of the rate standard lowers the full marginal cost by $\leftarrow$ , so the rate-standard technology is dispatched first, e.g., gas under the rate standard is dispatched before coal under the CAT. As illustrated, the merit order is efficient, because all the gas-fired generation is used before the coal-fired generation as demand increases.

However, the efficiency of supply only occurs because the full marginal costs are sufficiently different. If the full marginal costs are close, i.e., if $|c_C + \square_C \; - c_G - \square_G \;| < \leftarrow$ , then the merit order is not efficient. As illustrated in panel (d) of Fig.1 the full marginal costs are sufficiently close that the merit order is rate-standard gas, followed by rate-standard coal, then CAT gas, and then CAT coal. This merit order is inefficient since the full marginal social cost of gas-fired generation is less than the full marginal social cost of coal.[13]

Result 1 also highlights the importance of coordination across states. For CATs, all carbon prices need to be sufficiently close to , which can be ensured by carbon trading and

[13] This inefficiency from mixed regulation is limited, because it only arises if full marginal costs are sufficiently close, i.e., if costs are small from the wrong merit order.

a correct overall cap. Note that with carbon trading the distribution of the cap across states is irrelevant. With rate standards, trading can again ensure that carbon prices are equal across states. However, now the standards must be set equally across states in order for the merit order to be efficient, i.e., the distribution of the rate standards across the states is crucial. The result also shows an additional inefficiency if states fail to coordinate on a CAT or a rate standard.

This result also emphasizes the importance of carbon prices. Importantly, efficient supply depends on the carbon price being sufficiently close to , but does not depend on the target emissions level or the target emissions rate. Thus, to attain efficient supply, the regulator would need to adjust the emissions cap or target emissions rate to maintain the carbon price equal to . Unfortunately, the Clean Power Plan specifies emissions rate targets rather than carbon price targets.

Result 1 shows the increasingly stringent conditions under which the different regulations can lead to an efficient supply, i.e., an efficient merit order. However, efficiency of supply is necessary but not sufficient for overall efficiency of a regulation, as the following corollary makes clear:

Corollary 1. Efficiency: *If demand is perfectly inelastic, then CATs, rate standards, or mixed regulation achieve efficiency if the merit order is efficient.*

*If demand is not perfectly inelastic, then CAT regulations achieve efficiency if* $p_{cs}$ = *for all* s. *Rate standards and mixed regulation do not achieve efficiency.*

This corollary echoes earlier results in the literature (e.g., see Helfand (1991), Kwoka (1983), Holland, Hughes and Knittel (2009)). If demand is perfectly inelastic, then there is no consumption inefficiency and efficiency only requires efficient supply. However, if demand is not perfectly inelastic, then only a CAT regulation with a carbon price of can attain the first best.[14]

Given the importance of equal carbon prices in Result 1, the next result addresses the benefits from carbon trading, which equates carbon prices across regions.

Result 2. Carbon Trading: *Trading carbon between states reduces costs. Trading between states with CATs holds aggregate emissions constant. Trading between states with rate standards may cause aggregate emissions to increase or decrease.*

[14] Holland (2012) shows that rate standards can attain the first best if they are coupled with an electricity tax of $\sigma\tau$.



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This result shows that although carbon trading does reduce costs, it may not have clear efficiency benefits. Under CATs aggregate emissions are held constant and thus a reduction in costs leads to a clear efficiency gain. Under rate standards, aggregate emissions could increase or decrease, and thus the welfare effects are indeterminate.

We next compare the equilibrium outcomes across policies in which all states adopt the same policy. We analyze electricity prices, consumer surplus, and profits to "uncovered generators," namely, generators which are not covered by the regulation, e.g., renewables or distributed generation.

Result 3. Prices, Consumer Surplus, and Uncovered Generator Profits: *For a given carbon price* $p_{cs} > 0$,

*(i) electricity prices are higher under CATs than under either rate standards or no regulation, i.e.,* $p_t^{CAT} \geq p_t^{RS}$ *and* $p_t^{CAT} \geq p_t^{BAU}$*, and electricity prices under rate standards or under mixed regulation can be either higher or lower than under no regulation;*

*(ii) consumer surplus is lower under CATs than under either rate standards or no regulation, i.e.,* $CS^{CAT} \leq CS^{RS}$ *and* $CS^{CAT} \leq CS^{BAU}$*, and consumer surplus under rate standards or under mixed regulation can be either higher or lower than under no regulation; and*

*(iii) profits for uncovered generation are higher under CATs than under either rate standards or no regulation, and profits for uncovered generation under rate standards or under mixed regulation can be either higher or lower than under no regulation.*

For a given carbon price, this result shows that electricity prices are higher under CATs but can be higher or lower than BAU prices under rate standards. These price comparisons follow from a comparison of the full marginal costs under the policies. Since full marginal costs are higher under CAT than under rate standards or BAU, the electricity price is higher. Similarly, since the full marginal costs under rate standards can be higher or lower than under BAU, the electricity prices are similarly higher or lower. The results on consumer surplus and profits of uncovered generation follow directly from the result on prices.

The result on uncovered generation is important since significant generation capacity may not be covered by the Clean Power Plan, e.g., hydro, nuclear, and some combined heat and power. The result shows that these uncovered generators will prefer CAT regulation because they would benefit from the higher electricity prices. The effect is somewhat different for "dirty" and "clean" uncovered generators. For dirty uncovered generators, the benefit arises from the higher electricity prices and because the lack of carbon regulation does not increase their costs. For clean uncovered generators, the difference arises from the higher electricity prices and because the lack of carbon regulation does not *decrease* their costs under rate standards. The inability to sell carbon credits under a rate standard implies that uncovered clean generation prefers CAT. Note that this result also implies that incentives are strongest under CAT for new clean generation and for efficiency improvements both of which might be uncovered by the Clean Power Plan.

The result also has important implications for investment incentives. Investment will occur in the most profitable locations. New fossil-fuel fired generation may be "uncovered" since it is subject to other regulations, e.g., Section 111(b), and may not be subject to the Clean Power Plan. Renewables and small combined heat and power will also likely not be covered by the Clean Power Plan. The result implies that there would be more investment in uncovered generation under CAT regulation than under rate standards.

We next analyze the incentives for states to adopt either CATs or rate standards. We begin by analyzing the outcomes if states coordinate on either a single CAT or a single rate standard. To focus the analysis, we assume additionally that carbon prices equal and rate standards are equal across states, i.e., we assume that supply is efficient.

Result 4. Adoption Incentives of a Coalition: *Suppose that all states adopt the same regulation, i.e., all states have a unified CAT or unified rate standard. Suppose further that the CAT or rate standard results in a carbon price equal to the social cost of carbon across both regimes and across all states, i.e.,* $p_{cs} =$ *for all* s*, and that rate standards are equal across states, i.e.,* $\leftarrow_s = \leftarrow$ *for every* s.

*(i):* $p_t^{CAT} \leq p_t^{RS} + \leftarrow$ *for all* t;

*(ii):* $\sum_s \sum_i \sum_t q_{sit}^{CAT} \leq \sum_s \sum_i \sum_t q_{sit}^{RS}$

*(iii):* $\vdash_{si}^{CAT} \leq \vdash_{si}^{RS}$ *for all* s *and* i;

*(iv):* $\sum_s \sum_i \sum_t (c_i + \square_i) q_{sit}^{CAT} \leq \sum_s \sum_i \sum_t (c_i + \square_i) q_{sit}^{RS}$;

*(v):* $Carbon^{CAT} \leq Carbon^{RS}$;

*(vi):* $W^{CAT} \geq W^{RS}$; *and*

*(vii):* $TR^{CAT} - (Carbon^{RS} - Carbon^{CAT}) \geq (C^{RS} - C^{CAT}) + (\vdash^{RS} - \vdash^{CAT})$.

*If additionally we assume that demand is perfectly inelastic, then each of the weak inequalities above is an equality.*

This result compares the outcomes when states coordinate on CATs or rate standards and all carbon prices equal . Much of the intuition of the result comes from the comparison



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of the electricity prices in Result 4 (i) This result shows that although electricity prices are lower under rate standards, the drop in prices is bounded by ← . Because full marginal costs are lower by ← under rate standards, prices are also lower by exactly this amount if demand is perfectly inelastic. If demand is not perfectly inelastic, then a price which is lower by ← could result in excess demand. Thus the price difference is at most ← .

Because electricity prices are lower under rate standards and the merit order is unchanged, it follows that generation, generation costs, and carbon emissions are higher. Generator profits are also higher under rate standards, despite the lower electricity prices because full marginal costs are lower. Because full marginal costs are lower by ← and prices are lower by at most ← , generator profits increase.

The inefficiency of rate standards, described in Corollary 1, implies the result on welfare in Result 4 (vi). Rewriting this in Result 4 (vii) shows that the sum of carbon market revenue and the increase in carbon market damages exceeds the sum of the increases in consumer surplus and profit under rate standards.

With perfectly inelastic demand this equality becomes $CS^{CAT} + TR^{CAT} = CS^{RS}$, which shows that the gain in consumer surplus from a rate standard is exactly the foregone carbon market revenue $TR^{CAT}$. In this case, the carbon market revenue is exactly sufficient to compensate consumers for the lost consumer surplus under CATs.

If demand is not perfectly inelastic, the inequality in (vii) is much less informative about the ability of carbon market revenue to compensate consumers and producers for their losses under a CAT. In particular, it shows that carbon market revenue plus the additional carbon damages would be sufficient to compensate both producers and consumers for their losses under CAT. However, the result suggests that it is an empirical question whether or not carbon market revenue by itself will be sufficient to compensate both producers and consumers for their losses under CAT.

## 3.5 Incentives for Regulatory Choice

We now turn to the adoption incentives of an individual state. In particular the question of how a state's choice interacts with other states' choices to influence economic outcomes. This question can be directly addressed by the previous results in cases where the carbon prices are exogenous to the specific mechanism. For example if the mechanism were a carbon tax, rather than an emissions cap.



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If carbon prices were exogenous, then Result 4 would be a good guide to the adoption incentives of a single state.[15] As in Result 4 (i) if the state adopted a rate standard instead of a CAT, electricity prices would be lower in any hour in which that state's generators were marginal, but the electricity price would be lower by at most $\leftarrow_s$ . Since generators' costs would be lower by $\leftarrow_s$ , generators' profits would be higher under the rate standard. With lower electricity prices, consumer surplus would also be higher under a rate standard. Thus consumers and covered generators would prefer that their state adopt the rate standard regardless of what other states do. In other words, adoption of a rate standard would be a dominant strategy from the perspective of covered generators or consumers. On the other hand, lower electricity prices and no carbon market revenue imply that CAT adoption would be a dominant strategy from the perspective of government revenues and of uncovered generators. Thus, with fixed carbon prices, some perspectives would have dominant strategy for adoption of a CAT but others would have a dominant strategy for adoption of a rate standard.

Since the Clean Power Plan specifies emissions rates rather than carbon prices, carbon prices are likely to be endogenous to the regulatory choices of neighboring states. This complicates a single state's adoption decision. Most likely endogenous prices increase the potential benefits to states of not coordinating with neighboring states. For example, suppose a state were to consider a CAT when all its neighbors adopt a rate standard. With an exogenous carbon price, the full marginal costs would be higher under the CAT and thus the state's generators would be dispatched less frequently under the CAT. However, when prices are endogenous, the increased imports would lower domestic emissions and hence relax a capped emissions constraint.[16] This implies that the state's carbon price would be lower if it adopted a CAT instead of an equivalent rate standard. By contrast, a state choosing a rate standard when its neighbors are under CAT could experience either an increase or decrease in its carbon price, depending upon the mix of available supply in that state. For example if the rate state had excess "clean" generation capacity then increasing exports from those clean sources would relax the rate standard constraint and hence lower carbon prices.

With endogenous carbon prices, we can construct an example where adoption of mixed regulations lowers carbon costs for both CAT and rate states. Compliance costs and electricity prices would then be lower compared to a uniform CAT scheme. A state's adoption incentives will hence involve a combination of carbon price effects in addition to the effects outlined in Result 4. To assess the magnitude of these effects, we turn to a numerical

[15] Result 5 in Supplementary Appendix A extends Result 4 to analyze the adoption incentives of a single state assuming carbon prices are fixed at $\tau$.

[16] Intuitively, the state can achieve compliance through importing.



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simulation model.

# 4 Numerical simulations

The theoretical model describes the inefficiencies which can result when states choose CAT regulation or rate standards across an integrated product market. As described above, there are several additional considerations to the actual Clean Power Plan that are difficult to capture in a theoretical model, including the heterogeneity of both supply technologies and emissions limits across states, and importantly, the endogeneity of carbon prices a market's choice of regulatory mechanism. We approach this richer set of issues using numerical simulation methods applied in the context of the electricity market in the western US. We utilize an electricity transmission and supply model similar to that used in Bushnell and Chen (2012) (BC 2010) and Bushnell, Chen and Zaragoza-Watkins (2014) (BCZ 2011). The model has been calibrated using market data from the year 2007. In this section, we present the simulation model and the data used to parameterize the model. Additional details on the numerical simulation are in Online Appendix C

## 4.1 Optimization model and constraints

Because we assume firms act in a manner consistent with perfect competition in both the electricity and emissions permit markets, market equilibrium is equivalent to the solution of a social planner's problem.[17] Our social planner's problem maximizes gross consumer surplus less generation costs subject to constraints. Using the notation developed above, the planner's objective is thus:[18]

$$\max_{q_{sit}} CS + \sum_s \sum_i \sum_t (p_t - c_i) q_{sit}. \tag{3}$$

Maximization of Eq. 3 is subject to generation, transmission, and policy constraints. Generation constraints reflect installed capacity adjusted proportionally for the probability of a forced outage of each unit.[19] Unit forced outage factors are taken from the generator

[17] Although the California market was notorious for its high degree of market power in the early part of this decade, competitiveness has dramatically improved in the years since the California crisis, while the vast majority of supply in the rest of the WECC remains regulated under traditional cost-of-service principles.

[18] The objective does not consider carbon damages, which are addressed through the constraints.

[19] This approach to modeling unit availability is similar to Wolfram (1999) and Bushnell, Mansur and Saravia (2008).

availability data system (GADS) data that are collected by the North American Reliability Councils.

Our transmission constraints replicate centralized locational marginal pricing (LMP). Any LMP price differences are arbitraged away subject to the constraints of the transmissions network.[20] Our model divides the electricity market in the western U.S. into five transmission regions. Optimization of Eq. 3 is therefore subject to constraints on the flows between these five regions. These constraints are governed by existing line capacities. See Supplemental Appendix C.3 for more detail on our modeling of transmission constraints.

The carbon policies are modeled with additional constraints. BAU is modeled by optimizing Eq. 3 subject to the generation and transmission constraints. Under CAT regulation in state s, total emissions in the state must also be less than allowed emissions, i.e., the policy constraint is $\sum_i \sum_t \beta_i q_{sit} \leq E_s$. If two states harmonize their CAT regulations through emissions trading, aggregate emissions across the two states must be less than total allowed emissions. The shadow values of the constraints are the carbon prices that would result from implementation with market mechanisms. Similarly, if state s adopts a rate standard, then the emissions rate in the state must be less than the allowed emissions rate: $\sum_i \sum_t \beta_i q_{sit} / \sum_i \sum_t q_{sit} \leq \sigma_s$. If two states harmonize their rate standards, then the constraint is on the aggregate emissions rate. Note that this is equivalent to allowing carbon trading *plus* harmonizing the allowed emissions rates. The shadow values are again the resulting carbon prices.[21]

## 4.2 Market demand

We model electricity demand in each of four regions for each of 80 representative time periods (20 periods for each of four seasons).[22] To create the 80 representative time periods, we sort California aggregate generation into 20 bins based upon equal MW spreads between the minimum and maximum generation levels observed in the 2007 sample year.[23] Demand in the representative time period is based on the mean of electricity prices and consumption within each bin in 2007. To aggregate, we weight each representative time period by the

[20] Arbitrage of price differences across locations could be achieved through either bilateral transactions or a more centralized operation of the network.

[21] Below we equivalently write the rate standard constraints as $\sum_i \sum_t \beta_i q_{sit} \leq \sigma_s \sum_i \sum_t q_{sit}$ so that the shadow value is in dollars per ton of carbon.

[22] Although hourly data are available, for computational reasons we aggregate these data into representative time periods.

[23] California was the original focus of this work so aggregation is based only on California generation.



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number of season-hour observations in each bin.[24]

We assume linear demand where the intercept in each time period is determined by the mean hourly electricity price and consumption.[25] For electricity prices, we use hourly market prices in California and monthly average prices taken from the Intercontinental Exchange (ICE) for the non-market regions.[26] For electricity consumption, FERC form 714 provides hourly total end-use consumption by control-area which we aggregate to the North American Electric Reliability Commission (NERC) sub-region level. We apply EIA data on annual consumption by state to calculate the fraction of a region's demand that is attributable to a given state.

Because electricity demand is extremely inelastic, we utilize an extremely low value for the slopes of the linear demand curve. For example, in an early review article Taylor (1975) finds short-run price elasticities of electricity demand for residential consumers on the order of 0.15 with some estimates as high as 0.90. Commercial and industrial demand elasticities are estimated at 0.17 and 0.22 in the short-run. More recently, Kamerschen and Porter (2004) estimate total electricity demand elasticities in the range of 0.13 to 0.15 using US annual data from 1978 to 2008. Reiss and White (2005) estimate a mean elasticity of 0.39 for households in California while Ito (2014) estimates values consistently less than 0.10. Because the CPP affects the price of energy and approximately half of consumers' rate is related to non-energy charges, such as transmission, the response of consumers to changes in wholesale energy prices is likely even smaller. Therefore, the slope of the demand curve is set so that the median elasticity in each region is -.05.[27]

## 4.3 Fossil-fired generation costs and emissions

We explicitly model the major fossil-fired thermal units. Reliable data on the production costs of thermal generation units are available due to prior cost-of-service regulation within

[24] For example, in spring 2007 there were 54 hours in which California (residual) demand fell in the bin between 6949 and 7446 MW. To aggregate, resulting emissions from our representative time period are multiplied by 54 to generate an annualized equivalent total level of emissions.

[25] The intercept is the sum of mean consumption and the product of the mean price and demand slope.

[26] To obtain hourly prices in regions outside of California, we calculate the mean difference by season between the California prices and prices in other regions. This mean difference is then applied to the hourly California price to obtain an hourly regional price for states outside of California. Because demand in the model is very inelastic, the results are not very sensitive to this benchmark price method.

[27] Because the market is modeled as perfectly competitive, the results are relatively insensitive to the elasticity assumption, as price is set at the marginal cost of system production and the range of prices is relatively modest.



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the industry. The marginal cost of a modeled generation unit is estimated to be the sum of its fuel and variable operation and maintenance (VO&M) costs.

Generation marginal costs are derived from the costs of fuel and variable operating and maintenance costs for each unit in our sample. Fuel costs make up the largest share of marginal cost for thermal generation units. We calculate fuel costs for each unit as heat-rate multiplied by regional average fuel price. The marginal cost of each unit is therefore constant up to the capacity of the unit. We use unit average heat-rates and regional average fuel prices taken from the Platts PowerDat dataset. Emissions rates, measured as tons $CO_2$/MWh, are based upon the fuel-efficiency (heat-rate) of a plant and the $CO_2$ intensity of the fuel burned by that plant.

We examine the western electricity market under two different sets of conditions. We first use actual reported natural gas prices from 2007 to calibrate the model and establish if the simulation reasonably captures production and emissions totals over western states. However, natural gas prices have declined sharply since 2007. This has important implications for estimates of the costs of compliance with the CPP. Therefore, after establishing that the model accurately depicts market equilibrium outcomes using 2007 fuel prices, we re-simulate the market using natural gas prices that are, on average $2.00/mcf lower, to better capture current conditions. The results reported here utilize the lower natural gas prices representative of current prices.

In some scenarios, we consider investment in new combined cycle gas turbines (CCGT). Based upon information from the EIA, we assume that the annualized capital cost of a standard new CCGT would be $100 KW-yr. Operating costs $mc_{st}$ depend upon our natural gas price assumption and are assumed to be $48/MWh under 2007 gas prices and $32/MWh under current gas prices.

## 4.4 Uncovered generation

Our hourly market data include total demand and hourly production of all fossil-fired generation monitored by the EPA's continuous emissions monitoring system (CEMS). These constitute almost all the units units whose emissions would be regulated under the Clean Power Plan, *i.e.* covered generation. Unfortunately, we lack data on the hourly production from other sources, namely, renewable resources, hydro-electric resources, nuclear, combined heat and power, and other small thermal resources. We infer aggregate hourly production from these sources from the difference between regional consumption and fossil-fired generation after accounting for net imports. These sources, which consist of production with very



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low or zero marginal costs, are assumed to operate with the same hourly production in all of our simulations. We do not observe imports into an individual state for a given hour. Instead net imports are aggregated to the regional level within the western interconnection (WECC) and approximated from data on the hourly flow over key transmission lines between regions.

Thus we have a detailed picture of the total thermal and non-thermal supply in a region, but not of the hourly composition of the non-thermal output. We must instead infer that from EIA data (Form 860) that provides output by source and state on a monthly basis. Using these data we calculate the monthly average fraction of regional non-thermal generation that comes from each non-thermal source (e.g., nuclear, renewables, etc.) and each state in a region. We apply that fraction to the hourly regional data and simulation results to dis-aggregate those results to the state level.

In some results we disaggregate the outcomes for supply between generation sources covered under the clean power plan and "uncovered" sources. Covered sources include all measured fossil generation which emit $CO_2$. Under CAT these are the only plants that are directly impacted by the regulation. For the CPP, the EPA has proposed a complex formula that gives partial credit for output from nuclear plants and also credit for output from non-hydro renewable sources. Technically such sources may be eligible to earn emissions credit payments by virtue of their emissions rates being below the emissions rate standard. However because of our data limitations we include all non-thermal sources in our "uncovered" category when summarizing the results below.

Similarly, we apply EIA data on annual consumption by state to calculate the fraction of a region's demand that is attributable to a given state. Both of these approximations assume that the hourly distribution of regional non-thermal supply and demand amongst states is the same as the monthly or annual average of those distributions.

Appendix Table A.9 summarizes the generation totals and emissions for each of the states coming from covered and uncovered sources based upon EIA data and compares those data to the results of our simulation. These simulation results assume no $CO_2$ regulation and therefore constitute the "business as usual" case.

# 5 Simulation results

In this section we present simulation results under a variety of possible policy scenarios. In each case, the reductions required by each state are based upon the EPA's targeted reductions for the second "building block" of their abatement estimates. These are the EPA's



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expected carbon savings from re-ordering the generation so that low carbon sources run more frequently and, at least partially, displace higher carbon (e.g., coal) sources. We focus on this building block for two reasons. First, this building block captures the largest emissions reductions. Second, simulating the other building blocks requires further assumptions about energy efficiency improvements and investment in future generation.[28] The second building block requirements vary widely by state, ranging from the 40% reduction in emissions intensity for Arizona to no reductions at all from Montana and Idaho. These emissions reductions are illustrated in Appendix Figure A.1. Following the theory model, we begin by discussing supply-side effects of regulations on the generation merit order. Then, we analyze short-run equilibrium outcomes under each policy and incentives to form coalitions. Finally, we explore incentives for investment in new capacity under different regulations.

## 5.1 Supply-side effects

We first illustrate the effects of the regulation on the market supply functions. Instead of comparing the market supply curves for different regulations, we illustrate the market supply curve for one regulation and then show the full marginal costs for each generation unit under different regulations. The market supply (or merit order) under the different regulations could be determined by "re-sorting" the generating plants along the x-axis.

Figure 2 compares the full marginal costs of fossil-fuel generation units under West-wide CAT and rate standards to the market supply under BAU (i.e., the generating units are sorted along the x-axis by BAU marginal costs). The generating units to the left of 23 GW are coal-fired and the generating units to the right of 23 GW are gas-fired. The CAT standard (West-wide CAT) increases the full marginal costs of the units in proportion to their carbon emissions. Thus CAT changes the merit order so that some gas-fired generation is cheaper than coal-fired generation, i.e., the gas-fired generation would be used first as demand increases.

The rate standard (West-wide standard), increases the full marginal costs of the coal-fired generation because these plants have emissions rates which are worse than the standard. However, the rate standard *decreases* the full marginal costs of most of the gas-fired generation because these plants have emissions rates which are better than the standard.

This figure illustrates the high correlation between the merit orders under West-wide CAT and rate standards. This correlation illustrates the theoretical result that both CAT

[28] In the west, the CPP requires an average reduction of 36% in the emissions rate. Of this, the four building blocks contribute 4%, 15%, 9%, and 9% respectively.



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and rate standards can eliminate the supply-side inefficiency by correcting the merit order. However, although the relative costs of the technologies can be correct, the figure shows that full marginal costs are too low under the rate standard.[29]

Figure 3 illustrates the merit order that arises if states fail to harmonize their CAT standards. The figure illustrates the supply curve for a CAT standard (West-wide Cap) and compares it with state-by-state CAT standards (State CATs). The state-by-state caps lead to full marginal costs which are too high in some states—those with tight caps—and too low in other states—those with loose caps. This heterogeneity "scrambles" the merit order and is an additional source of inefficiency.[30] Practically speaking, this can lead to very different dispatch behavior of similar generating units, which is clearly inefficient.

Figure 4 illustrates the merit order when regional coalitions fail to coordinate policies. This figure compares a West-wide CAT with mixed regulation in which coastal states adopt a CAT standard and inland states adopt a rate standard. The merit order is scrambled so effectively with mixed regulation that almost all the inland plants have lower full marginal costs than any of the coastal plants! Of course, transmission constraints would prevent such an extremely inefficient dispatch, so estimating the inefficiency of these scrambled merit orders requires calculating the equilibria under the various regulations.

## 5.2 Short-run equilibria

There are many metrics one could use to evaluate the impacts of these regulations. We focus on the standard economic metrics of consumer surplus, producer profits, abatement, abatement costs, and deadweight loss.[31]

We next analyze short-run equilibria across different policy types in nine different scenarios.[32] Scenario 0, represents no regulation, *i.e.* BAU, establishes a baseline level of costs and emissions by simulating the western market without any GHG regulations. Scenarios 1 through 8 vary which states operate under CAT and rate standards.

We first investigate effects across the different policy types. The odd numbered scenarios assume states operate under the same CAT or rate standard, and can therefore trade across

[29] Again, we assume the cap is set optimally such that full marginal costs under CAT are efficient. Under the rate standard, full marginal costs are lower than those under CAT and are often less than the unregulated case where carbon emissions are unpriced.

[30] Appendix Figure A.4 shows a similar "scrambling" of the merit order due to state-by-state rate standards.

[31] Recall, we define abatement cost as the sum of consumer surplus, producer surplus, and any carbon market revenue.

[32] Below we allow investment in new generation capacity.



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state lines to achieve the required emissions reductions. In Scenario 1, western states operate under a single CAT standard. Scenario 3 assumes a single standard for all states. Scenario 5 models a single CAT for coastal states and a single rate standard for inland states.[33] Scenario 7 assumes the opposite, coastal states have a rate standard, while inland states are regulated with CAT.

Next, we explore the effects of policy coordination. The even numbered scenarios assume each individual state has their own CAT or rate standard. In Scenario 2, each state has a state-specific emissions CAT system. Scenario 4 assumes state-specific rate standards. Scenario 6 assumes inland states have state-specific rate standards, while coastal states operate under a single CAT. Finally, Scenario 8 assumes coastal states have different rate standards, while inland states have a single CAT standard.

Table 1 reports equilibrium prices, profits, and changes in welfare across the different scenarios. In Scenario 1, prices increase by roughly \$20 per MWh, relative to business-as-usual, under a single western-states CAT. The quantity of electricity consumed falls by 3 percent, while emissions fall by 17 percent, implying that changes in the merit order are largely driving emission reductions.[34] The equilibrium permit price, reflecting the price of carbon, is roughly \$35 per metric ton of $CO_2$. We note this closely matches the social cost of carbon used by the EPA in regulatory filings.

We next calculate the change in consumer and producer surplus prior to any redistribution of carbon permit revenue. We compute the change in consumer surplus and the producer surplus of power plants regulated under the CPP—"covered" plants—and plants that are not regulated under the CPP—"uncovered" plants. Consumer surplus falls by \$14.14 billion under a single western CAT system. The producer surplus of plants regulated under the CPP falls by \$2.48 billion, while profits of uncovered plants increase by roughly \$6.36 billion. Producer surplus rises for these plants because electricity prices increase and uncovered plants are not required to pay additional carbon costs. The net impact, therefore, on producer surplus is an increase of approximately \$4 billion. Profits from transmission decrease slightly relative to business as usual. Despite the reduction in generation, production costs increase slightly due to changes in the merit order. The implied carbon market revenue for permit sales exceeds \$9 billion.

[33]Coastal states are California, Oregon and Washington. Inland states are Arizona, Colorado, Idaho, Montana, New Mexico, Nevada, Wyoming and Utah.

[34]We note that this is in contrast to Holland, Hughes and Knittel (2009) and Holland et al. (Forthcoming) which find that, within transportation, the majority of emission reductions come from lowering fuel consumption as opposed to shifting to lower greenhouse gas emitting fuels (ethanol). This is due, in part, to our demand elasticity of 0.05 compared to 0.50 in their baseline simulations.



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The abatement cost of emission reductions is $1.15 billion, resulting in an average abatement cost of $21.95 per ton of $CO_2$. In calculating deadweight loss, we assume the reductions required by EPA accurately reflect the social cost of carbon. In other words, we assume the social costs of carbon are equal to the marginal abatement costs under the most efficient form of abatement, a west-wide CAT system.[35] Therefore Scenario 1, a west-wide CAT program, produces zero deadweight loss, by definition.[36] The drop in carbon damages necessarily exceeds abatement costs by $0.69 billion—the deadweight loss under no regulation.[37]

This scenario serves as a baseline to compare alternative regulation regimes. The next regulatory regime, Scenario 2, assumes that each state operates under their own CAT system. Therefore, this scenario will not necessarily equate marginal abatement costs across the states. Electricity prices increase slightly compared to a single cap, from $59.80 to $68.17/MWh. By definition, emission reductions are the same, but average permit prices increase by roughly $9/MT.[38]

Consumers are harmed by state-level CAT systems, given the higher prices, but firms are better off. Profits of covered plants fall by $0.72 billion compared to $2.44 billion under a single CAT system and producer surplus of uncovered plants increases by $9.21 billion or about $3 billion more than under CAT. The increase in production cost is slightly less under the multiple CAT standards, while abatement costs are slightly higher. The average abatement cost is roughly $3.50 per metric ton greater compared to a single CAT standard. While less efficient than a single CAT, multiple state CAT systems reduce the amount of deadweight loss by approximately 75 percent compared to no regulation.

We next analyze rate standards. Scenario 3 imposes a single rate standard for the western states. Under a single rate standard electricity prices rise slightly compared to no regulation. Abatement is slightly greater than under CAT. The shadow value of emission reductions is $47.91 per metric ton. The higher electricity prices decrease consumer surplus slightly, producer surplus decreases for covered but increases for uncovered plants. The average abatement costs increase by 16 percent compared to a single CAT system. Finally, deadweight loss decreases by 75 percent compared to no regulation.

In our simulations, state-specific rate standards create massive inefficiencies. Average electricity prices increase to $85/MWh, an unrealistically high level compared with

[35] In other words, we assume the emissions cap is optimally set.

[36] The implied cost of carbon is $35.10 which is well within the range of estimates of the social cost of carbon and similar to the EPA's assumed SCC of $37/MT of $CO_{2e}$.

[37] The other scenarios, including no regulation, produce some deadweight loss either due to inefficient levels of emissions or excessive abatement costs.

[38] We report the weighted-average electricity price and permit price, weighted by state-level consumption.



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$40.38/MWh in the unregulated case, Scenario 0. This leads to much larger emission reductions compared to first best, a drop of 75.16 million metric tons versus a drop of 52.45 million metric tons. The shadow value of emission reductions increases dramatically to approximately $287.64 per metric ton. The higher prices lead to lower consumer surplus and higher profits compared to either no regulation or a single CAT. Average abatement costs are nearly *double* those of a single CAT standard. More importantly, social welfare falls under multiple rate standards by $1.24 billion compared to first best and by $0.55 billion compared to no regulation ($1.24B to $0.69B).

Our next set of scenarios model either the coastal or inland states forming a CAT coalition while the remaining states adopt state-level or a single rate standard. These simulations will in turn help us understand the incentives these two coalitions might have to join a western-wide CAT program. Scenario 5 assumes a coastal-state-wide emissions CAT and a single rate standard for inland states. Under this scenario average electricity prices are $53.65/MWh, falling between the West-wide CAT and West-wide rate scenarios. Emissions fall by 49.04 MMT of $CO_2$, compared to 52.45 MMT under the West-wide CAT scenarios and 75.16 MMT under the state-specific rate standards. Permit prices are $33.23/MT in the CAT market, lower than the West-wide CAT, while the shadow value of the rate constraint is $89.40/MT, considerably higher than under a west-wide rate. Both consumer surplus falls while producer surplus increases for both covered and uncovered generation. There is little carbon market revenue ($1.78B) consistent with fewer coastal emissions covered by the CAT system. Most importantly average abatement costs are higher than a West-wide CAT despite the fact that abatement is lower. Furthermore, a considerable amount of deadweight loss remains; deadweight loss falls by only 50 percent relative to the unregulated case.

Scenario 6 replaces the single inland rate-standard with state-specific standards. Not surprisingly average prices increase considerably, as does abatement. We find that such a scenario *increases* deadweight loss by 13 percent, relative to the unregulated case though average abatement costs are not as high as scenario 4 (state-specific rate standards for every state).

Our final two scenarios assume that coastal states adopt either a single rate standard or state-specific standards, while inland states adopt a single CAT. Given that California currently has a cap-and-trade system in place, we do not believe our last two scenarios are realistic, but they provide the basis for understanding the complete set of incentives. Interestingly, we find that an inland CAT system with rate standards in the west dominates the coastal CAT system combined with inland rate standards. That is, welfare improves more under these scenarios than under scenarios 5 and 6.

We next turn to state-specific welfare changes. Table 2 calculates the welfare changes for each state, as well as the two blocks of states discussed above, under each of the scenarios. We assume that carbon-market revenues are returned to consumers and producers in a lump-sum fashion. This table makes clear the divergent incentives of coastal and inland states. The coastal states prefer a single rate standard, Scenario 3, while inland states are most harmed by such a standard. The intuition for this result is that coastal generation sources are, on average, cleaner than inland generators. Therefore under a single rate standard, more coastal generators are implicitly subsidized, while more inland generators are taxed, giving coastal power plants a competitive advantage when the market operates under a single rate standard. Notice that state-specific rate standards (Scenarios 4 and 6) do not lead to such a competitive advantage.

Table 3 focuses on changes in producer surplus. Here the incentives across states are more aligned, since producer surplus depends heavily on equilibrium electricity prices. Producers in both coastal and inland states prefer state-specific rate standards, which as we have shown leads to large increases in the price of electricity. Across Scenarios 5 through 8, each block of states prefers to face state-specific rate standards, but we find that coastal generators benefit, relative to business-as-usual in each of these scenarios.

## 5.3 Incentives to form a West-wide coalition

Our simulations suggest that efficiency is enhanced when states form regional trading markets. A natural question, then, is whether states will have the incentive to form such a coalition? We analyze the incentives of the two blocks of states defined above: coastal and inland states. This division is somewhat reflective of current policy discussions.

Table 4 is the normal form representation of the change in abatement cost or private surplus (ignoring transmission revenues and carbon damages) across the two regions. CAT adoption yields carbon market revenue and tends to benefit uncovered generation but harm consumers and covered generators. The social-surplus perspective assesses whether the benefits outweigh the harms, and hence whether it is possible to compensate losers and to align incentives. As shown, the inland region gains from adopting CAT, regardless of the regulation in the coast. For the coastal region, gains outweigh losses if the inland has a CAT, but not if inland has a rate standard. Thus, the best regulation for the coast depends on the regulation in the inland region. The "Nash equilibrium" is the efficient regulatory mechanism: CAT/CAT (i.e., Coastal CAT/Inland CAT).[39] Thus it is possible according to our

[39] Appendix Figure A.7 shows the state-by-state distribution of the abatement costs. Although the inland



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calculations to compensate losers and to align incentives for a West-wide CAT coalition.

When we look at the individual sets of stakeholders, CAT/CAT is no longer an equilibrium. Table 5 presents the payoff matrix to consumers. If carbon prices were unaffected, consumers would prefer rate standards. This generally holds except when inland states adopt a CAT. In this case, adoption of the rate standard increases the carbon price from $35.10 to $190 (!) in the coastal states. Since this carbon price causes higher electricity prices, coastal consumers would prefer a CAT if inland states adopt a CAT. Nonetheless, if consumers choose the regulatory mix, the Nash equilibrium would be Rate/Rate, i.e., a West-wide *rate-standard* coalition.

These first two results imply that if left to the social planner, or to consumers, the regulatory mechanism would be the same across the coalition: CAT/CAT if the planner and Rate/Rate if consumers. As we have seen from Table 1, this has important implications for economic efficiency.[40]

The incentives of firms differ dramatically. Table 6 represents the change in profits across both covered and uncovered generators.[41] If carbon prices were unaffected, covered generators would generally prefer rate standards and uncovered generators would generally prefer CAT. Thus any outcome is possible depending on the relative importance of covered and uncovered generators. We see that there is a strong incentive to have different regulatory mechanisms; CAT/Rate and Rate/CAT are both Nash equilibria.[42]

Several points are worth noting. First aggregate profits are much higher to generators under mixed regulation. Thus a firm with generation in both regions could have an incentive to support rate standards in one region but CAT in the other. Second, if there is a CAT inland, then both covered and uncovered generation would benefit from a rate standard. Similarly, if there is a rate standard inland, both covered and uncovered generation would benefit from a CAT. Thus generators' incentives align for the Rate/CAT equilibrium due to

states as a group always gain from adopting CAT, not all states gain. For example, ID would be harmed more by adopting a CAT standard if the coastal states also adopt CAT than if the inland states adopted a rate.

[40] The consumer's perspective is also illustrated in Appendix Figure A.8 for the individual states. This figure shows the dominance of Rate/Rate from the consumer's perspective. In particular, it illustrates the losses for California consumers under CAT.

[41] Appendix Figure A.9 illustrates changes in generator profits for individual states. Appendix Table A.10 shows profit for covered generators and Appendix Table A.11 shows profit for uncovered generators.

[42] Appendix Table A.10 and Appendix Figure A.10 focus on the profits of covered generators. Once again we find that only disparate regulation is a Nash equilibrium, but we can narrow the equilibrium to Rate/CAT, which curiously is an unlikely outcome given that California has already established a CAT program. We find the same unique Nash equilibrium (in pure strategies) when we look at the profits of uncovered generation in Appendix Table A.11 and Appendix Figure A.11.



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its exceptionally high electricity prices ($61.38). Finally, given the failure of the West-wide coalition, generator profits are much higher in the region with a rate standard. This would imply the potential for a first-mover advantage if either one of these regions could commit to choosing a rate standard or a first-mover disadvantage if one of the regions has committed to a CAT.

Combined, these results imply that there is very little incentive for formation of a West-wide CAT coalition. While the Nash equilibrium from the social planner's perspective is a West-wide CAT coalition, consumers prefer a West-wide rate standard coalition, and generators prefer mixed regulation. Thus incentives are not aligned across market participants for the formation of the efficient West-wide CAT coalition.

## 5.4 Entry incentives

Another important dimension over which states and the EPA will need to evaluate their compliance plans is the treatment of newly constructed fossil-fired power plants. Technically, Section 111d of the Clean Air Act covers only existing sources. New sources are regulated separately and will have to comply with a source-specific $CO_2$ emissions rate standard. At the time of this writing, the extent to which state-level plans may or may not include new plants under their Clean Power Plan compliance strategies has not been resolved.

We examine this question by adjusting our baseline simulations in two ways. First we anticipate demand growth by escalating hourly demand for every state by 10% over 2007 levels. Second, we allow firms in each state the option of constructing new combined cycle gas turbines (CCGT). As described previously, these plants are assumed to cost $100 kw-yr, with a marginal cost of $32/MWh at current gas prices. They have an assumed emissions rate of .428 tons/MWh. We assume these costs do not differ across states.

The specification of the investment decision was described in section 4. Essentially, new MW of CCGT capacity are added when the sum of the net revenues (net of MC) exceeds the $100 KW-yr threshold. Capacity is added until such investments just break even. Last we assume that under every environmental regulation scenario, the emissions goal is set equivalent to those established in our baseline simulations without new entry.

The efficiency effects of the different scenarios with investment are shown in the supplementary online materials. Specifically, Appendix Table A.12 presents equilibrium outcomes when new investment is included under the CPP. Appendix Table A.13 presents results when



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new investment is excluded. In general, we see that the average abatement cost is much lower if new investment is included in the CPP. This is true under both CAT and rate standards.[43]

Of course the net revenues of such investments will depend upon the regulatory treatment of not just new sources but also of existing sources. Table 7 summarizes the total additional new CCGT capacity that would be added in each region (coastal or inland), under different combinations of regulatory policies and policies toward new generation. Because of demand growth, there is new investment under every scenario. If we assume that the EPA targets are optimal, then the scenario with all states and new units under CAT would produce the first-best outcome. Relative to this, excluding new plants from the CAT regulation substantially increases the amount of new CCGT capacity from about 3716 MW to 6353 MW. Conversely, new investment is 5977 MW when new gas capacity is included under a rate standard, and this declines to 4520 MW when new capacity is excluded.

When we examine the mix of regulations, the contrary incentives provided by the two regulations are highlighted. In general, excluding new plants encourages investment under CAT and discourages it under rate standards. When new plants are included, investment is favored under rate standards relative to CAT. When the coastal states adopt CAT and the inland states adopt rate standards, this influence is magnified. Despite an underlying economic benefit of coastal investment, when new plants are included under the regulations *all* new investment occurs in the inland states, which are operating under a rate standard. When new plants are excluded, this influence reverses and much of the new investment migrates back to the coastal states. However, 3543 MW of new capacity is also built in the rate states, essentially for export back to the coastal states. Overall, under this scenario 9471 MW of new gas capacity are constructed, almost triple that of what could be considered the first-best level.

# 6 Conclusion

There are many contexts in which environmental regulation and trade can interact to undermine the efficiency of both. The EPA's Clean Power Plan is a clear and timely example of these interactions. The CPP proposes major reductions in carbon emissions from generators of electricity, a good that is perfectly substitutable across neighboring states. The CPP establishes state-level targets for carbon emissions rates in lbs of carbon dioxide per megawatt

[43] If new investment is included in the CPP, average abatement costs are \$24.62 per MT of $CO_2$ under CAT and \$27.42 per MT of $CO_2$ under a rate standard. If new investment is not included in the CPP, average abatement costs are \$35.60 per MT of $CO_2$ and \$31.07 per MT of $CO_2$ under CAT and rate standards.



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hour of electricity generated. States have a great deal of flexibility in how to achieve these goals. Because this flexibility creates different incentives, effects on consumers and producers within a state could be quite different depending on the type of regulation adopted both in that particular state as well as in other states because electricity is traded regionally across state lines. Furthermore, the states' private incentives may be at odds with those of a social planner.

In this paper we have focused on the two likely market-based regulatory approaches that could be adopted by states, a mass-based (CAT) approach, and a rate standard. Our theoretical findings imply that efficiency is most likely achieved under CAT, and that a mix of CAT and rate standards is likely to create an inefficient "ordering" of generation resources. Further we find that, while consumers in each state may prefer to coordinate on rate standards, producers can prefer to coordinate on inconsistent regulations, where different states adopt different approaches.

We investigate the importance of our theoretical findings using numerical simulations of the electricity market in the western United States. We find lack of coordination, when states independently pursue their own emissions targets without regard to electricity trading partners, leads to large inefficiencies. For example under state-specific caps, average abatement costs are 16% higher than under a uniform CAT standard. Under state-specific rate standards, average abatement costs can nearly double relative to a uniform CAT standard. Regional cooperation does little to mitigate these concerns. When two regions of the west coordinate internally, but adopt different instruments, average abatement costs remain 17-29% higher than costs under a uniform CAT standard. Unfortunately, we find generator incentives do not favor coordination and may lead to adoption of less efficient mixed policies.

One unresolved aspect of the CPP is whether new natural gas generation is included in state emission rates. We examine the implications of the CPP on the construction of new natural gas generation under a medium-term outlook where demand grows by 10% relative to 2007 levels. We find that whether new plants are covered under the CPP can dramatically change where new plants are built. When new plants are included in CPP compliance new generation shifts out of CAT regions toward rate regions.

Overall, our findings indicate that despite the *opportunities* the CPP provides for states to coordinate and implement compliance plans that can efficiently achieve their joint targets, the incentives of individual states to participate in those plans are conflicted. Indeed, there can easily be circumstances when states find it in their own interest to adopt a regulatory approach that is contrary to those of its neighbors.



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## Tables



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Table 1: Equilibrium outcomes for business as usual and eight policy scenarios.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| Electricity Price ($/MWh) | $ 40.38 | $ 59.80 | $ 68.17 | $ 41.02 | $ 84.68 | $ 53.65 | $ 72.78 | $ 61.38 | $ 74.96 |
| Electricity Quantity (GWh) | 411,362 | -13,133 | -18,863 | -405 | -30,050 | -9,141 | -22,304 | -14,283 | -23,310 |
| Emissions (MMT) | 313.81 | -52.45 | -52.45 | -52.70 | -75.16 | -49.04 | -69.70 | -54.07 | -59.79 |
| CAT Permit Price ($/MT) | | $ 35.10 | $ 44.36 | | | $ 33.23 | $ 63.48 | $ 30.19 | $ 41.30 |
| Rate Permit Price ($/MT) | | | | $ 47.91 | $ 287.64 | $ 89.40 | $ 187.48 | $ 190.91 | $ 331.18 |
| Consumer Surplus ($ bn.) | $ 417.36 | -$14.14 | -$20.36 | -$0.33 | -$33.09 | -$10.00 | -$24.06 | -$15.70 | -$25.66 |
| Covered Generator Profit ($ bn.) | $ 6.47 | -$2.48 | -$0.72 | -$1.10 | + $14.48 | + $2.24 | + $7.04 | + $0.85 | + $3.57 |
| Uncovered Generator Profit ($ bn.) | $ 13.48 | + $6.36 | + $9.21 | + $0.14 | + $15.06 | + $4.55 | + $10.97 | + $7.09 | + $11.61 |
| Transmission Profit ($ bn.) | $ 0.14 | -$0.07 | -$0.01 | -$0.06 | + $0.36 | + $0.04 | + $0.10 | + $0.10 | + $0.18 |
| Production Costs ($ bn.) | $ 12.69 | + $1.19 | + $0.91 | + $2.42 | + $2.42 | + $1.80 | + $2.45 | + $1.39 | + $0.99 |
| Carbon Market Rev. ($ bn.) | | + $9.17 | + $10.54 | | | + $1.78 | + $3.40 | + $6.27 | + $8.58 |
| Abatement Cost ($ bn.) | | -$1.15 | -$1.33 | -$1.34 | -$3.19 | -$1.39 | -$2.53 | -$1.39 | -$1.72 |
| Avg. Abatement Cost ($/MT) | | + $21.95 | + $25.41 | + $25.46 | + $42.46 | + $28.25 | + $36.34 | + $25.72 | + $28.74 |
| Carbon Damages ($ bn.) | | -$1.84 | -$1.84 | -$1.85 | -$2.64 | -$1.72 | -$2.45 | -$1.90 | -$2.10 |
| Deadweight Loss ($ bn.) | -$0.69 | + $0.00 | -$0.18 | -$0.18 | -$1.24 | -$0.35 | -$0.78 | -$0.18 | -$0.31 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. "Abatement Cost" is the sum of consumer surplus, profits (covered, uncovered, and transmission), and carbon market revenue. Carbon damages assume a social cost of carbon equal to $35.10.



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Table 2: Social welfare gains across regions relative to business as usual under eight policy scenarios.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| Social Welfare ($ bn.) | | | | | | | | | |
| CA | $176.20 | -$0.43 | -$1.19 | + $2.06 | -$2.44 | -$0.25 | -$1.13 | -$0.44 | -$1.93 |
| OR | $30.55 | + $0.13 | + $0.09 | + $0.22 | + $0.13 | + $0.08 | + $0.07 | -$0.01 | + $0.09 |
| WA | $54.30 | + $0.33 | + $0.08 | + $0.11 | -$0.13 | + $0.16 | + $0.13 | -$0.29 | -$0.14 |
| Coastal Total | $261.05 | + $0.03 | -$1.01 | + $2.38 | -$2.45 | -$0.01 | -$0.92 | -$0.74 | -$1.98 |
| AZ | $50.56 | + $0.71 | + $0.53 | + $0.38 | + $0.94 | + $2.11 | + $0.63 | + $0.59 | + $1.25 |
| CO | $27.00 | + $0.06 | -$0.00 | -$0.47 | -$0.30 | -$0.44 | -$0.36 | + $0.18 | + $0.23 |
| ID | $14.39 | -$0.24 | -$0.41 | + $0.07 | -$0.71 | -$0.13 | -$0.49 | -$0.33 | -$0.50 |
| MT | $10.02 | -$0.04 | + $0.28 | -$0.36 | + $0.49 | -$0.42 | + $0.36 | + $0.12 | + $0.18 |
| NM | $14.40 | -$0.36 | + $0.18 | -$0.34 | + $0.06 | -$0.38 | + $0.01 | -$0.30 | -$0.35 |
| NV | $22.43 | -$0.06 | -$0.14 | + $0.23 | + $0.00 | + $0.72 | -$0.00 | -$0.04 | -$0.04 |
| UT | $17.21 | + $0.21 | + $0.18 | -$0.45 | -$0.33 | -$0.40 | -$0.39 | + $0.25 | + $0.41 |
| WY | $9.24 | + $0.45 | + $0.90 | -$0.87 | + $1.39 | -$0.75 | + $0.98 | + $0.68 | + $1.01 |
| Inland Total | $165.24 | + $0.72 | + $1.52 | -$1.82 | + $1.54 | + $0.31 | + $0.73 | + $1.15 | + $2.18 |
| Transmission Profits | $0.14 | -$0.07 | -$0.01 | -$0.06 | + $0.36 | + $0.04 | + $0.10 | + $0.10 | + $0.18 |
| Total | $426.43 | + $0.69 | + $0.51 | + $0.51 | -$0.55 | + $0.34 | -$0.09 | + $0.51 | + $0.38 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. Carbon damages assume a social cost of carbon equal to $35.10. Carbon damages are allocated across states based on population.



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Table 3: Generator profits across regions for all generation (covered and uncovered) under business as usual and eight policy scenarios.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| CA | $5.64 | + $2.85 | + $3.84 | + $1.22 | + $9.16 | + $1.62 | + $4.53 | + $4.66 | + $7.19 |
| OR | $1.97 | + $0.67 | + $1.07 | + $0.07 | + $2.76 | + $0.51 | + $1.43 | + $1.20 | + $2.02 |
| WA | $3.98 | + $1.35 | + $2.09 | -$0.16 | + $4.51 | + $1.05 | + $2.79 | + $1.84 | + $3.25 |
| Coastal Total | $11.59 | + $4.88 | + $7.00 | + $1.12 | + $16.42 | + $3.18 | + $8.75 | + $7.71 | + $12.46 |
| AZ | $2.47 | + $0.77 | + $1.14 | + $0.38 | + $3.85 | + $2.95 | + $2.85 | + $0.63 | + $1.86 |
| CO | $1.26 | -$0.37 | -$0.22 | -$0.50 | + $1.75 | + $0.14 | + $1.17 | -$0.12 | + $0.13 |
| ID | $0.40 | + $0.16 | + $0.25 | + $0.01 | + $0.59 | + $0.23 | + $0.42 | + $0.23 | + $0.37 |
| MT | $0.87 | -$0.19 | + $0.75 | -$0.41 | + $1.34 | -$0.18 | + $0.96 | + $0.04 | + $0.18 |
| NM | $0.56 | -$0.31 | -$0.04 | -$0.35 | + $0.89 | -$0.14 | + $0.64 | -$0.28 | -$0.16 |
| NV | $0.51 | + $0.17 | + $0.26 | + $0.20 | + $1.50 | + $1.15 | + $1.11 | + $0.21 | + $0.54 |
| UT | $0.99 | -$0.53 | -$0.42 | -$0.55 | + $1.15 | + $0.01 | + $0.64 | -$0.16 | -$0.01 |
| WY | $1.29 | -$0.69 | -$0.24 | -$0.85 | + $2.05 | -$0.55 | + $1.48 | -$0.31 | -$0.19 |
| Inland Total | $8.36 | -$1.00 | + $1.49 | -$2.08 | + $13.12 | + $3.61 | + $9.27 | + $0.23 | + $2.72 |
| Total | $19.95 | + $3.88 | + $8.49 | -$0.96 | + $29.54 | + $6.79 | + $18.01 | + $7.94 | + $15.18 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. Profits in $ billion.



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Table 4: Abatement cost incentives in the coastal and inland west.

| | | Inland CAT | | Inland Rate | |
|---|---|---|---|---|---|
| Coastal | CAT | - $1.23 | + $0.14 | - $1.19 | - $0.23 |
| Coastal | Rate | - $2.04 | + $0.55 | + $1.12 | - $2.40 |

Notes: "Abatement Cost" is the sum of consumer surplus, generator profits (covered and uncovered), and carbon market revenue and is measured relative to business as usual (Scenario 0) in $ billion. "+" indicates an increase (i.e., a gain) and "-" indicates a decrease (i.e., a loss).

Table 5: Consumer surplus incentives in the coastal and inland west.

| | | Inland CAT | | Inland Rate | |
|---|---|---|---|---|---|
| Coastal | CAT | - $8.38 | - $5.75 | - $6.15 | - $3.84 |
| Coastal | Rate | - $9.74 | - $5.96 | - $0.00 | - $0.32 |

Notes: Consumer surplus is measured relative to business as usual (Scenario 0) in $ billion. "+" indicates an increase and "-" indicates a decrease.

Table 6: Profit incentives for all generation (covered and uncovered) in the coastal and inland west.

| | | Inland CAT | | Inland Rate | |
|---|---|---|---|---|---|
| Coastal | CAT | + $4.88 | - $1.00 | + $3.18 | + $3.61 |
| Coastal | Rate | + $7.71 | + $0.23 | + $1.12 | - $2.08 |

Notes: Profit is measured relative to business as usual (Scenario 0) in $ billion. "+" indicates an increase and "-" indicates a decrease.



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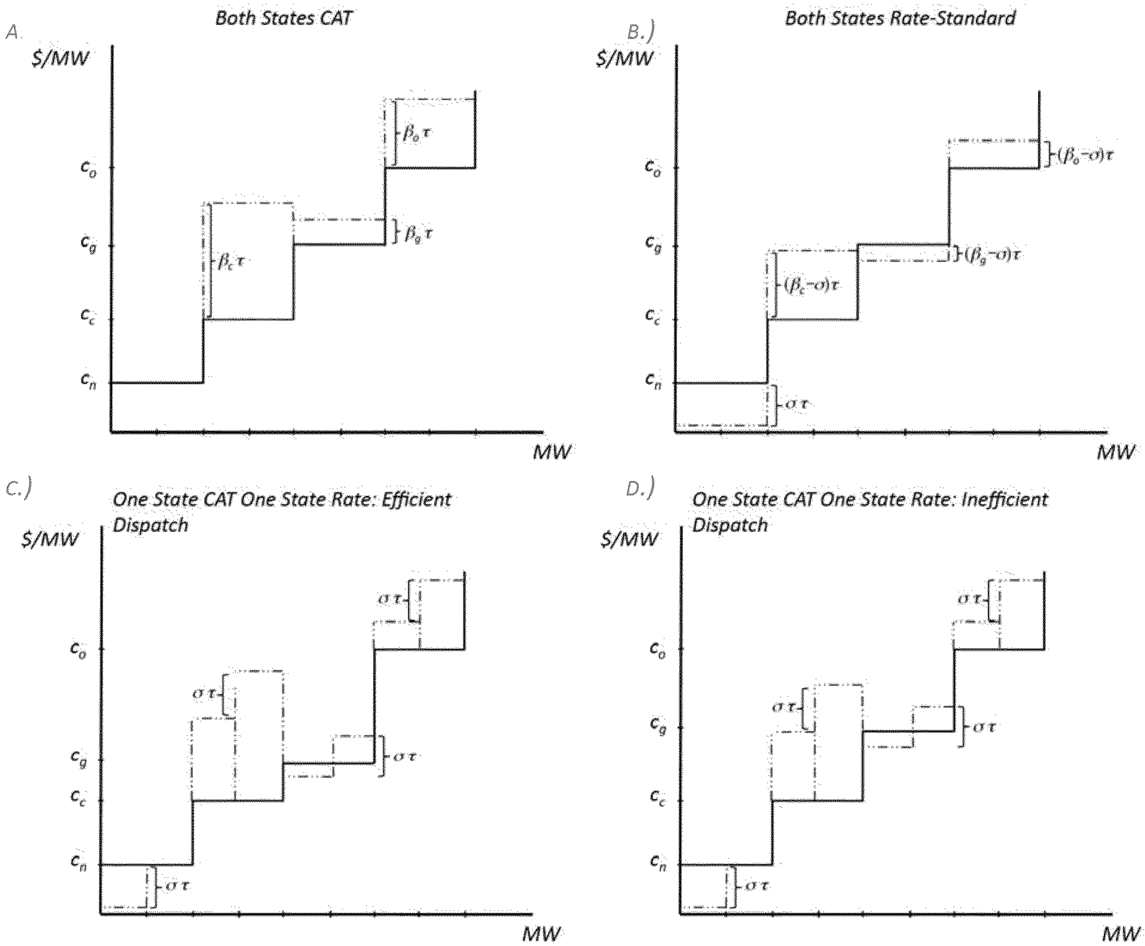
Table 7: New capacity under four policy scenarios when new NGCC investment is included and *not* included under the CPP.

| New Capacity (MW) | CAT (Mass-Based) | | | Rate ‐6WDQGDUG | | | Coast CAT & Inland Rate | | | Coast Rate & Inland CAT | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Coast | Inland | Total | Coast | Inland | Total | Coast | Inland | Total | Coast | Inland | Total |
| Included | +3,355 | +361 | +3,716 | +4,931 | +1,046 | +5,977 | +0 | +6,081 | +6,081 | +10,273 | -1,177 | +9,095 |
| Excluded | +5,922 | +431 | +6,353 | +2,402 | +2,118 | +4,520 | +5,928 | +3,543 | +9,471 | +5,937 | +1,042 | +6,979 |

Note: Results are reported as changes relative to new capacity built under business as usual. ``+" indicates an increase and ``-" indicates a decrease. Scenarios assume 10% load growth from 2006 levels.

# Figures

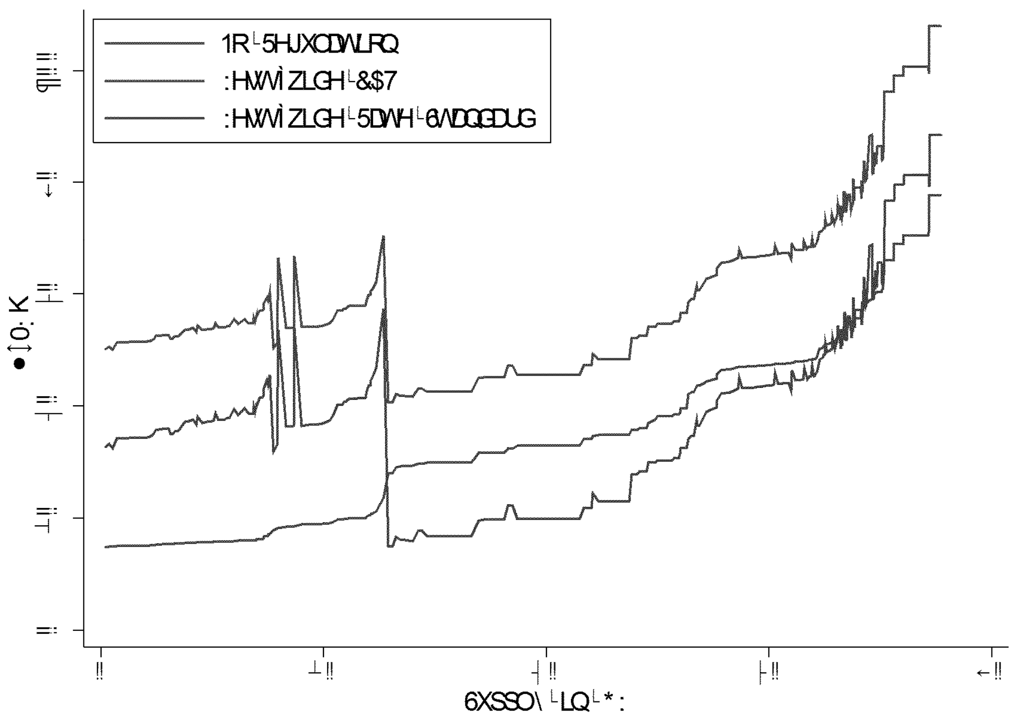
Figure 1: Full marginal costs under different regulatory regimes.






ED_000584A_00001552

Figure 2: Merit order under different regulations: BAU and West-wide CAT and rate standards.



Note: Generating units sorted on x-axis by marginal costs under BAU (Scenario 0).



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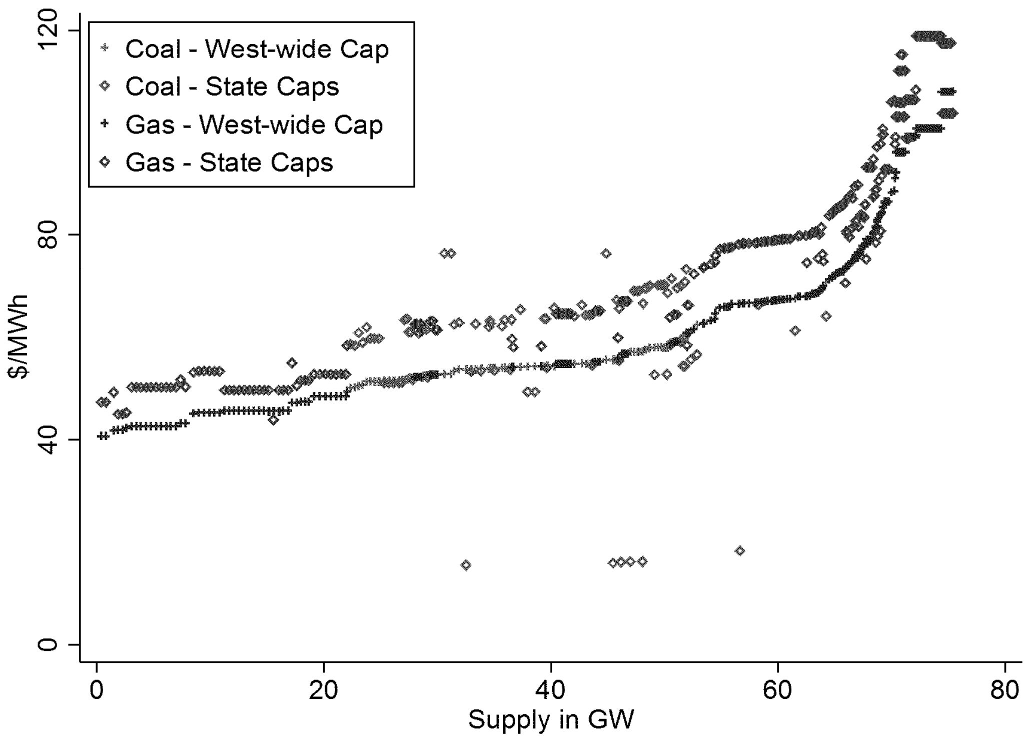
Figure 3: Merit order under different regulations: West-wide CAT standards and state-by-state CAT standards.




Note: Generating units sorted on x-axis by full-marginal costs under West-wide CAT standards (Scenario 1).



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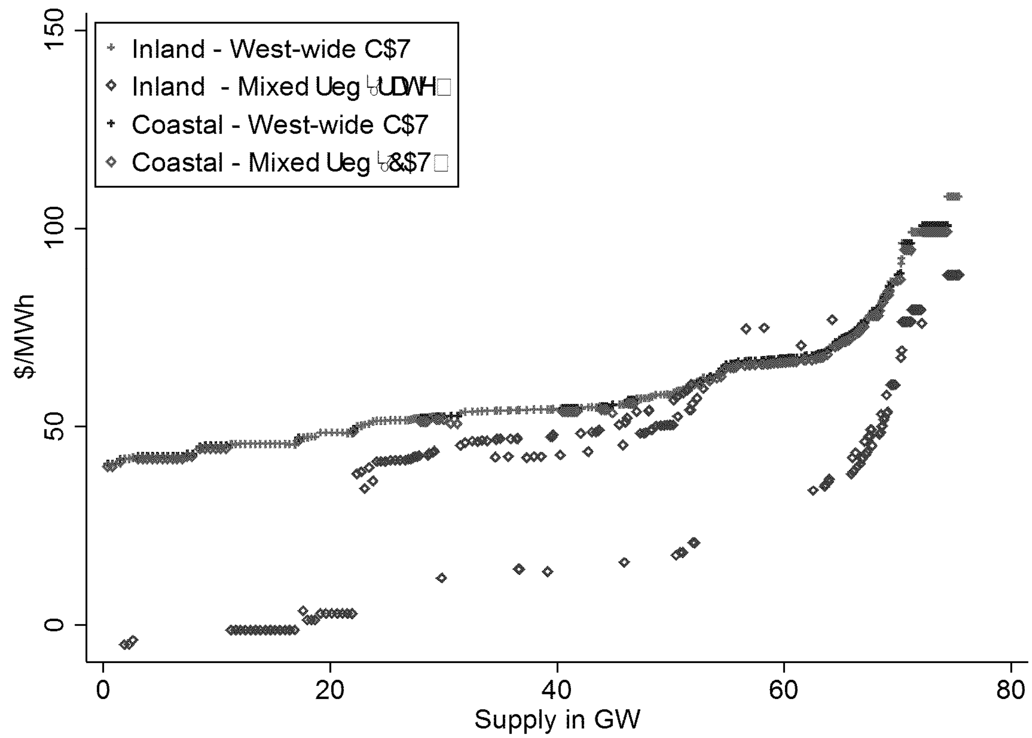
Figure 4: Merit order under different regulations: West-wide CAT standards and mixed regulation.




Note: Generating units sorted on x-axis by full-marginal costs under West-wide CAT standards (Scenario 1). Mixed regulation has Coastal CAT standard and Inland rate standard.



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**To:** Macpherson, Alex[Macpherson.Alex@epa.gov]; Evans, DavidA[Evans.DavidA@epa.gov]
**Cc:** Marten, Alex[Marten.Alex@epa.gov]
**From:** Ferris, Ann
**Sent:** Mon 8/3/2015 1:15:18 PM
**Subject:** RE: Two paper for d docket
2011_StavinsSchmalansee_TransportRuleReport.pdf
anger08.pdf
berman_bui2001.pdf
chan13.pdf
commins09.pdf
Ehrenberg_Smith_7th_ed_2000_ch4.pdf
Graff_Zivin_Neidell_AER_Dec_2012_.102.7.pdf
Greenstone_JPE2002.pdf
Hamermesh_1993_ch2.pdf
kahn_mansur2013.pdf

Hi,

I'm not sure if the employment chapter references ended up in the docket – Glenn was working on that and I was on maternity leave.

I have most of what's cited, and isn't readily available on the web (with URLs listed in the references). However, it's all copyrighted (I think). I'll attach half the papers I have to this email, then send a second.

If it's helpful, we uploaded a bunch of these papers, but not all, to the Tier 3 final docket.

Here's a link to the Layard & Walters chapter: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0135-5136

Hamermesh: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0135-5137

And Ehrenberg & Smith: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0135-5135

Thanks,

Ann

_____
Ann Ferris
U.S. Environmental Protection Agency
National Center for Environmental Economics
(202) 564-3207

**From:** Ferris, Ann
**Sent:** Monday, August 03, 2015 8:38 AM
**To:** Macpherson, Alex; Evans, DavidA
**Cc:** Marten, Alex
**Subject:** RE: Two paper for d docket

I'm looking at this now. Will send any papers, if needed, asap.

Ann

**From:** Macpherson, Alex
**Sent:** Monday, August 03, 2015 7:37 AM
**To:** Evans, DavidA
**Cc:** Marten, Alex; Ferris, Ann

**Subject:** RE: Two paper for d docket

I'll try to get them in. If you get a chance, please check in with Ann if there are any papers cited in final that weren't at proposal, and see if we can get those in too.

Alex

**From:** Evans, DavidA
**Sent:** Sunday, August 02, 2015 9:58 PM
**To:** Macpherson, Alex
**Cc:** Marten, Alex
**Subject:** Two paper for d docket

Alex Mac.,

Hope these are still useful.

d

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# Firm competitiveness and the European Union emissions trading scheme $

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## HIGHLIGHTS

- We examine the impact of European Union Emissions Trading Scheme (EU ETS) on firms' unit material costs, employment and revenue during 2005–2009.
- EU ETS had no impact on the performance of cement and iron and steel industries.
- EU ETS was associated with increased material costs and revenue of the power industry.
- We find no evidence of negative impact on firm competitiveness from EU ETS during 2005–2009.

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## abstract

The European Union Emissions Trading Scheme is the first international cap-and-trade program for $CO_2$ and the largest carbon pricing regime in the world. A principle concern over the Emissions Trading Scheme is the potential impact on the competitiveness of industry. Using a panel of 5873 firms in 10 European countries during 2001–2009, this paper seeks to assess the impact of the carbon regulation on three variables through which the effects on firm competitiveness may manifest—unit material costs, employment and revenue. Our analysis focuses on three most polluting industries covered under the program-power, cement, and iron and steel. Empirical results indicate that the emissions trading program had different impacts across these three sectors. While no impacts are found on any of the three variables in cement and iron and steel industries, our analysis suggests a positive effect on both material costs and revenue in the power sector: the effect on material costs likely reflects the costs to comply with emissions constraints or other parallel renewable incentive programs while that on revenue may partly due to cost pass-through to consumers in a market less exposed to competition outside EU. Overall our findings do not substantiate concerns over carbon leakage, job loss and industry competitiveness at least during the study period.

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## 1. Introduction

The European Union Emissions Trading Scheme (EU ETS) is the world's first large implementation of a $CO_2$ cap-and-trade system. Launched in 2005, it forms the centerpiece of EU's climate policy to reduce greenhouse gas emissions by 20 percent below 1990 levels before 2020. Under the system, each EU member state sets an annual cap limiting total $CO_2$ emissions from electric utilities and energy-intensive industrial plants. The government then divides the cap into individual allowances to emit one ton of $CO_2$ and allocates them to participating firms. At the end of every compliance year, each firm must deduct enough allowances from its account to cover its emissions for that year. Firms can trade allowances among each other, purchasing extra allowances if they emitted more, selling or saving allowances if they emitted less.[1] The EU's trading scheme effectively puts a price on carbon emissions via the trading price for

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[1] Banking of excess allowances for future years is allowed within the first compliance period (phase I of EUETS during 2005–2007), and is mandatory after 2012.

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allowances. Today more than 12,000 power generators and heavy manufacturing units in 30 countries are covered by the system.

Emissions trading programs such as the EU ETS have gained popularity over the past two decades as a market-based policy instrument to minimize the costs of environmental regulation. Experience in the United States has shown that well-designed emissions trading programs can reduce policy costs by between 15 and 90 percent compared to traditional command-and-control program (Schmalensee and Stavins, 2012; Carlson et al., 2000; Ellerman et al., 2000; Keohane, 2006). Although the cost-effectiveness of carbon trading is widely acknowledged, a major unresolved issue in the debate over EU ETS is whether it would impose an unsustainable burden on the industry.

The conventional wisdom is that environmental regulations even based on the market-based approaches could divert productive investment (Rose, 1983) or reduce operating flexibility (Joshi et al., 1997), therefore adversely affect firm productivity (Jaffe et al., 1995). More importantly, because EU was the first to impose carbon regulation, there is concern that such unilateral action would hinder the competitiveness of EU firms in the global market. Proponents of this view hold that stringent environmental regulations could actually enhance productivity growth by stimulating innovation and efficiency (i.e., the Porter hypothesis, Porter, 1991). Another concern is that emission-intensive firms in EU could relocate to regions with no or lesser carbon restrictions. The economic relocation would be accompanied by loss of jobs and market shares, as well as carbon leakage whereby emissions reduction in EU could be more than offset by increases elsewhere.

Two strands of literature have addressed the above questions on competitiveness and carbon leakage. The first are ex ante studies to simulate the potential carbon leakage in a range of energy-intensive manufacturing sectors. Based on assumptions on $CO_2$ prices, demand elasticities and trade exposure, these studies project leakage rates ranging from very low to significant at 30 percent or more (Ponssard and Walker, 2008; Demailly and Quirion, 2008; Reinaud, 2008 etc.). For example, Demailly and Quirion (2008) examines the impact on cement industry under a euro 20 per ton $CO_2$ price. They found that the leakage rates range from 0.5 to 25 percent among EU-27 countries with a mean value of 6 percent.

The literature on ex post empirical analysis is relatively thin. Abrell et al. (2011) assess the impact of EU ETS on firm competitiveness based on data of 2000 European firms during 2005–2008. They find no statistically significant impact of EU ETS on firm value added, profit margin or employment. Anger and Oberndorfer (2008) examine the impact of EU ETS on firm revenue and employment based on a sample of German firms over the period of 2005–2006. Their analysis suggests that the initial allocation of allowances did not affect revenue and the employment, therefore the impact of carbon regulation on firm competitiveness is likely to be modest. Jaraite and Maria (2011) investigate the effect of Phase 1 (2005–2007) EU ETS on productivity growth of the power generating sector using macro-level data of 24 European countries during 1996–2007. They find that carbon pricing had a positive impact on technological change. Overall, the existing empirical literature seems to find little evidence to support the hypothesis that EU ETS would have a large adverse impact on competitiveness.

In this paper, we measure the effect of EU ETS on firm unit material cost, employment and turnover based on a panel of 5873 firms in the electric power, cement and steel industry from 10 European countries[2] during 2005–2009. The power sector is the most heavily affected by the carbon regulation. During the sample period, the sector was short by around 440 million allowances[3] and was a net buyer of allowances within EU. The cement and iron industries are vulnerable to carbon leakage as both are tradable industries and cannot pass through increased energy costs into product prices without incurring a loss of market share. All together, the three (power, cement, iron and steel) sectors account for 86.76 percent of carbon emissions in the EU and constitutes 86.98 percent of total demand and 85.33 percent of total supply of carbon allowances.

We match firm financial data from the AMADEUS database maintained by Bureau van Dijk with emission traction records reported in the Community Independent Transaction Log (CITL) run by the European Commission. We then use participant and nonparticipant firms of similar sizes within the same industry category to construct the control and treatment groups. Using a fixed effects specification, we estimate the impact of carbon trading, as well as the initial allocation of allowances on firm competitiveness. Our analysis differs from previous research in two ways. First, unlike the study of Abrell et al. (2011) that uses firms from different (non-ETS) industries as the counterfactual, we compare performance of regulated and unregulated firms within the same industry. In doing so, we avoid potential bias by omitted variables characterizing time-variant differences among industries. Second, our study covers more industries, more countries and a longer period of the trading program than other studies. Therefore, our paper provides additional evidence on the impacts of the carbon regulation.

The results from this study suggest that EU ETS had different impacts across sectors. Our results show that the program may have resulted in higher material costs of the power industry on average by about 5 percent during 2005–2007 (Phase 1) and 8 percent during 2008–2009 (Phase 2). Since power sector as a whole faced a binding constraint of $CO_2$ emissions during the study period, rising material costs could reflect the compliance costs associated with purchasing allowances and/or substituting low-cost coal with more expensive fuel such as natural gas to mitigate emissions. It could also reflect the costs to comply with parallel renewable incentive programs. In addition, the turnover of the power companies on average increased by 30 percent in Phase 2. This could imply that fossil-fuel power generation companies have passed through compliance costs to ratepayers, resulting in higher electricity prices and higher revenue. On the other hand, the trading scheme seems to have had no statistically significant impacts on any of the three variables in the cement and iron and steel sectors. The differences between ETS and non-ETS firms in these two industries in material costs, employment and turnover are statistically insignificant. This finding suggests that there is likely to be no shift of production elsewhere. The free allocation of emission allowances gave firms a source of revenue and this could partially explain the limited impact of EU ETS so far.

The remainder of the paper is organized in the following. Section 2 provides a background of EU ETS. Section 3 describes data. Section 4 discusses the empirical strategy. Section 5 presents the results and Section 6 concludes.

## 2. The EU emissions trading scheme

The EU ETS was approved by European Commission in 2003 and officially launched in 2005. It was set up with three phases. Phase 1, from 2005 through 2007, was intended as much to gain business buy-in and develop institutions as to achieve

[2] Austria, Belgium, Czech Republic, France, Germany, Great Britain, Italy, Netherlands, Poland and Spain.

[3] These numbers are determined using the sample of 10 countries used in this study due to the need to identify power plants from the combustion sector.

$CO_2$ reductions. As a result, many regulated firms in the manufacturing sectors received more allowances than they subsequently needed to cover their emissions. Phase 2, which ran from 2008 to 2012, tightened the cap (6.5 percent below the 2005 emission levels). Though again the emerging evidence is that delivering the emission reductions required becomes easier and cheaper than expected, largely because of recession. Phase 3 which will run from 2013 to 2020 will implement steeper emission cutbacks (the cap will decrease each year by 1.74 percent), and move from free allocation of allowances to auction.

During the first two phases, the trading scheme covers energy-related $CO_2$ emissions[4] from power and heat generation and nine energy-intensive industries, including cement, iron and steel, oil refineries, coke ovens, and industries producing glass, lime, bricks, ceramics, pulp, paper and board.[5] However, not all firms in the regulated industries are obligated to participate in trading. A size threshold based on production capacity or output was used to determine the coverage within each sector. For example, participation of power utilities is limited to installations greater than 20 MW in capacity. For cement industry, the threshold is 500 metric tons of production per day. This participation eligibility provides an opportunity to create treatment and control groups within the same industry.

For each participating installation, an account is set up in its national emissions trading registry to record the issuance, transfer, cancellation, retirement and banking of allowances. All national registries are also connected to a central registry at the EU level—the Community Independent Transaction Log (CITL). The centralized registry tracks the ownership of allowances across the entire carbon market. Using information presented in CITL, we are able to identify participants and non-participants in the three trading sectors under study. We then choose firms that are similar in size (measured by turnover before the program) to form our treatment and control groups. More details on data construction are explained in the next section.

Another key element of EU ETS is the initial allocation of emission allowances. During the first two trading periods, the program gives national government substantial discretion in determining the allocation and distribution of allowances across sectors, subject to general guidelines by the European commission.[6] During 2005–2012, over 90 percent of the allowances were given out for free to trading sectors based on burden sharing obligations under the Kyoto Protocol, and individual installations' historical emission and projected abatement costs. Early evidence suggests that at the aggregate level power generation was the only sector receiving fewer allowances than verified emissions (Ellerman and Buchner, 2008). The power sector faced more stringent regulation because it is thought to have more low-cost abatement options and is less exposed to international competition.

Despite evidence of the over-allocation at the sector level, firms still have incentives to cut emissions since they can sell excess permits at the ongoing market price. Indeed, several studies suggest that $CO_2$ emissions dropped by around 3 percent relative to a baseline without ETS during the pilot phase (Ellerman and Buchner 2008; Ellerman et al., 2010; Anderson and Di Maria, 2011), and the first two years of Phase II (Abrell et al., 2011). There are several ways through which power utilities and industries can mitigate emissions. These include switching to low-carbon fuels, optimizing production processes, and investing on more efficient equipments and low-carbon technologies.

## 3. Data

The main data source of firm economic performance is the AMADEUS dataset from 2001 to 2009. AMADEUS is a commercial database containing financial information of more than 11 million firms in 41 European countries. Each firm in the database includes wide range of the standardized financial statement information[7] such as asset holdings, turnover, cost of employee, working capital and net income. The comprehensiveness of the dataset allows us to control for a number of firm characteristics and examine the effect of program participation in a number of dimensions. In this paper, we focus on three industries (power, cement, and iron and steel) that are allocated most permits (Trotignon and Delbosc, 2008) and investigate three different variables through which firm competitiveness can manifest—unit material cost (which is defined as the ratio of total material costs to turnover), number of employees, and turnover (revenue).

As discussed in Section 2, EU ETS covers installations in nine trading sectors (with specific size thresholds). To locate the participating firms, we first identify firms in the above three sectors in AMADEUS using NACE (revision 2, 4 digit class level) industry code.[8] We then manually match the AMADEUS firms with those in CITL. CITL contains observations at the installation level and we use the account holder in the CITL to locate their parent firm to aggregate multiple installations into one single firm. One difficulty in matching these two databases is that although AMADEUS has a precise sectorial classification (a NACE code), CITL defines sectors based on "activities". For example, the combustion sector defined in CITL includes a number of industries that incur combustion processes, such as power generation, food processing, pharmaceutical etc. In cases when sector classifications do not match, we use zip code, name of parent company, address and contact information to identify EU ETS firms.

We define program participation based on allowances submission—an installation is a participant if it surrenders a positive number of allowances in that year. Since a firm can have multiple installations and therefore several accounts in CITL, we sum across all the accounts matched with an AMADEUS firm to obtain firm-level allowance allocation and submission. We focus on 10 large countries, Austria, Belgium, Czech Republic, France, Germany, Great Britain, Italy, Netherlands, Poland and Spain.[9] Table 1 lists the top 15 countries in recorded emissions in CITL. The 10 countries covered in the analysis are among the biggest polluters. Table 2 shows the proportion of CITL installations that are

[4] With the exception of the Netherlands, which has opted in emissions of nitrous oxide.

[5] Aviation is included in the trading scheme as from 2012. When the third trading period start, the scope of the ETS will be further extended to cover more sectors and additional greenhouse gases.

[6] For the third trading period beginning in 2013, there will no longer be any national allocation plans. Instead, the allocation will be determined directly at the EU level.

[7] One potential problem of using financial statement information is the different closing dates of the accounting period. We define the observation as in year t if the accounting period ends on any date from April 1 in year t to March 31 in year t þ 1.

[8] We define power generation industry as firms in NACE 35.11 – "Production of Electricity"; the cement industry as the combination of NACE 23.51 – "Manufacture of Cement" and NACE 23.52 – "Manufacture of Lime and Plaster". There are multiple sub-sectors under iron and steel industry with drastically different products and processes, for the purpose of this analysis we define iron and steel firms as those with NACE 24.10 – "Manufacture of Basic Iron and Steel and of Ferro-Alloys".

[9] Our match of CITL and AMADEUS data is performed country by country. For the companies that are multi-national, our analysis treats the subsidiary/plants in each country as a separate entity. That is, our analysis ignores potential interactions (e.g., permit re-allocation) across these subsidiaries among these multi-national companies especially when the relevant markets (e.g., electricity market) are integrated across the host countries. Nevertheless, it is not clear how strong these interactions might be and how these interactions would affect our results.

Table 1
Top 15 polluting countries.

| Rank | Country | Verified emissions (million tonnes) |
|---|---|---|
| 1 | Germany[n] | 466 |
| 2 | Great Britain[n] | 247 |
| 3 | Italy[n] | 213 |
| 4 | Poland[n] | 203 |
| 5 | Spain[n] | 162 |
| 6 | France[n] | 122 |
| 7 | Netherlands[n] | 81 |
| 8 | Czech Republic[n] | 80.6 |
| 9 | Greece[1] | 67.9 |
| 10 | Belgium[n] | 52.5 |
| 11 | Finland | 38.7 |
| 12 | Romania | 38.3 |
| 13 | Austria[n] | 31.3 |
| 14 | Portugal | 30.5 |
| 15 | Denmark | 27.9 |

Note: The 'verified emissions' is a simple time average of the total verified emissions of all installations on the CITL record. Starred countries indicate the ones in our sample. The names and addresses of Greek firms in the AMADEUS database did not transcript properly so we did not try to match these installations and their respective firms.

Table 2
CITL—AMADEUS matching.

| Country | Matching proportion | | |
|---|---|---|---|
| | Power[a] | Cement | Iron[#] |
| Germany | 0.289 | 0.837 | 0.957 |
| Great Britain | 0.191 | 0.538 | 1.000 |
| Italy | 0.026 | 0.836 | 0.913 |
| Poland | 0.055 | 0.708 | 1.000 |
| Spain | 0.345 | 0.879 | 0.929 |
| France | 0.196 | 0.980 | 0.808 |
| Netherlands | 0.154 | ^ | # |
| Czech Republic | 0.099 | 0.818 | 1.000 |
| Belgium | 0.202 | 0.545 | 0.963 |
| Austria | 0.260 | 0.750 | ^ |

Note: ^: We are not able to match any of the six cement CITL installations in Netherlands, where five of the installations belong to the same firm. Therefore, we do not include any cement firms in Netherlands in our analysis. Similarly for iron industry, we are not able to match the one CITL installation for Austria and we drop all Austrian firms in iron and steel industry.
#: Due to a broader classification of the CITL sectors, we conduct our matching by including all industries under "Manufacture of Basic Metals", which may include manufacture of tubes, pipes, or other products of first processing of steel, but we only isolate firms that are in the primary iron and steel industry class (24.10). Thus we have dropped two Dutch installations, though they are matched, they do not belong to the primary industry class that we are focusing on.

[a] Since the matching proportions are based on CITL 9 sectors, the power industry is just a small part of the combustion sector therefore we have a low probability of matching for power, though we suspect that the non-matched ones do not belong to the power sector.

matched—the ratio of matched firms and total firms in each CITL sector. Though the power sector has a significantly low match ratio, most of the non-matched firms are identified as being in non-power sector, therefore we believe that our control group will not contain 'treated' firms.

Table 3 presents the summary statistics for both participating and non-participating firms by sector. As we can see from the last column, participants generally are bigger—they incur higher material and labor costs, and also have larger turnovers. This is not surprising given that only large emitters are regulated by EU ETS. However, the difference in size between participating and non-participating firms does impose a difficulty in estimating the causal effect (see more discussion in the next section). In order to create a robust control group to isolate the size effect we use the pre-program year in 2004 to choose non-participant firms that are 'close enough' to EU ETS firms. Specifically, we choose non-participant firms who have their 2004 turnover falling between the 25th and the 75th percentiles of the distribution of the turnover of the participant firms as the control group. Figs. 1–3 illustrate the trend in unit material cost of participating and non-participant firms. As we can see, for all the three sectors, the two groups share similar trends before the program started in 2005.

Table 3
Summary statistics by sector.

| | Participants | | Non-participants | | Difference |
|---|---|---|---|---|---|
| | Mean | N | Mean | N | Mean |
| Power generation | | | | | |
| Material cost | 92,630.0 | 1780 | 22,950.7 | 2216 | 69,518.6 |
| | (211,200.7) | | (43,962.0) | | (5,124.6) |
| Unit material cost | 0.59 | 1836 | 0.48 | 2189 | 0.11 |
| | (0.23) | | (0.29) | | (0.01) |
| Turnover | 93,427.1 | 2447 | 41,147.1 | 2954 | 51,743.4 |
| | (179,683.3) | | (72,926.0) | | (3,898.7) |
| Number of employees | 400 | 1615 | 105 | 1925 | 299 |
| | (739) | | (199) | | (19) |
| Cement | | | | | |
| Material cost | 49,105.0 | 694 | 22,933.5 | 466 | 25,658.4 |
| | (107,809.0) | | (23,622.9) | | (6,128.8) |
| Unit material cost | 0.33 | 732 | 0.49 | 464 | 0.17 |
| | (0.13) | | (0.17) | | (0.01) |
| Turnover | 181,456.2 | 848 | 47,263.1 | 558 | 134,692.7 |
| | (414,994.7) | | (52,461.5) | | (14,969.1) |
| Number of employees | 526 | 823 | 145 | 519 | 390 |
| | (1172) | | (151) | | (42) |
| Iron and steel | | | | | |
| Material cost | 299,008.1 | 590 | 183,656.3 | 408 | 115,810.4 |
| | (340,025.9) | | (183,532.6) | | (16,273.3) |
| Unit material cost | 0.62 | 643 | 0.68 | 406 | 0.06 |
| | (0.16) | | (0.15) | | (0.01) |
| Turnover | 432,463.9 | 617 | 244,547.3 | 489 | 185,733.0 |
| | (490,889.6) | | (233,898.6) | | (22,049.6) |
| Number of employees | 935 | 561 | 509 | 444 | 424 |
| | (1116) | | (541) | | (54) |

Note: For the first two columns the standard deviations are recorded in respective parentheses, while the standard errors are recorded in the last 'difference' column. The difference column also controls for year fixed effects. N denotes number of observations. 'Material cost' and 'Turnover' are nominal Euros, 'Unit material cost' is defined as ratio of the material cost to turnover. 'Number of employees' is the headcount of employees.

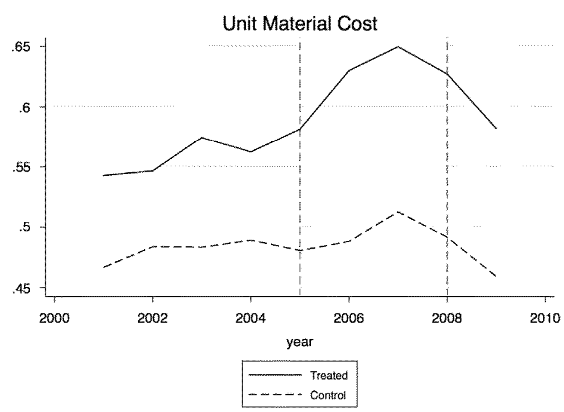


Fig. 1. Unit material cost trend for the power generation industry.

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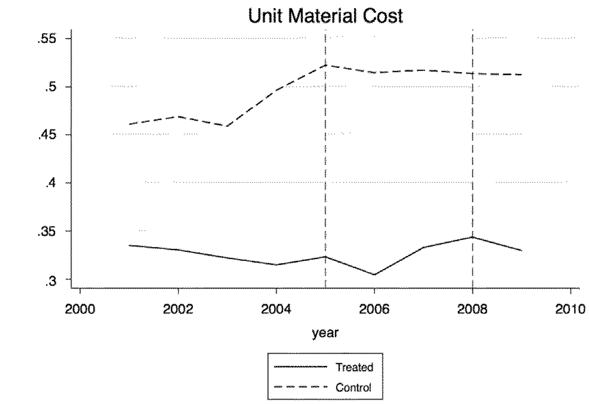


Fig. 2. Unit material cost trend for the cement industry.

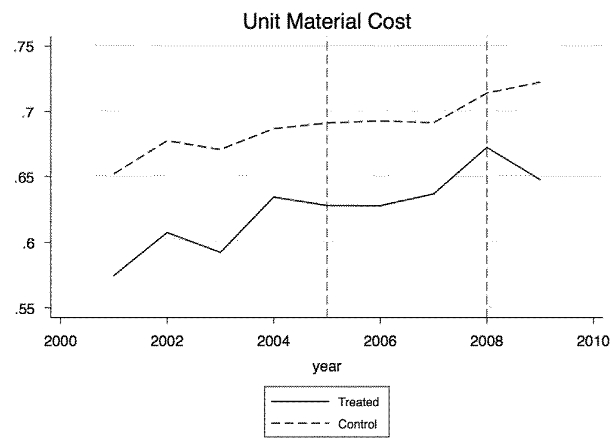


Fig. 3. Unit material cost trend for the iron and steel industry. Note: For the above figures, unit material cost is defined as the ratio of material cost to turnover.

We plot trends for the other two dependent variables of interest and the pre-program trends also look similar.

## 4. Empirical method

The goal of our empirical analysis is to examine the effect of EU ETS program on firm competitiveness. The key to estimate the treatment effect is to construct the counterfactual outcome for program participants in the absence of the program. If program participants were chosen randomly, one could just compare the outcomes from the participants and non-participants to estimate the treatment effect during the program period. However, the program requires an industrial installation in nine industry sectors to participate only if the capacity or thermal usage of the installation exceeds certain levels. Without randomized program assignment, we turn to difference-in-differences (DD) estimation by taking advantage of the panel nature of our data. By using non-participants as the control group, the DD method compares the differences in outcomes for participants (the treatment group) before and after the intervention with the same differences for the control group. By focusing on changes instead of levels, the method controls for time-invariant characteristics that could be correlated with the outcome variables. By comparing changes in the two groups, we can control for time trends that were constant across the two groups.

We specify the DD method through a two-way fixed effect linear regression model

$$y_{it} = \alpha d_{it} + x_{it}\beta + f_i + d_{ct} + u_{it} \qquad (1)$$

where i indexes a firm and t indexes year. $y_{it}$ is the logarithm of the outcome variable that we are interested in including unit material cost, number of employee, as well as turnover. $d_{it}$ is a dummy variable which is one if firm i is participating in the program at time t. The model also controls for observed time-varying covariates, $x_{it}$, a full set of firm effect, $f_i$, and a full set of country-year fixed effect, $d_{ct}$, where c indexes the host country of firm i. The firm fixed effects control for time-invariant firm-level factors that affect outcome variable, while the country-year fixed effects control for country-specific time trend such as macroeconomic conditions. $u_{it}$ is the idiosyncratic error term. In this setup, the OLS estimate $\hat{\alpha}$ can be used to estimate the average treatment effect.[10]

Although the model includes a full set of firm fixed effects $f_i$, and country-year fixed effects $d_{ct}$, the unbiasedness of $\hat{\alpha}$ as an estimator of the average treatment effect still relies on the following two critical assumptions. The first one is that the trends in the dependent variable over time captured by $d_{ct}$ should be the same across the treatment and control groups. This assumption could be violated if changes in variables faced by both groups (such as macroeconomic conditions) have different effects on the outcome variables across the two groups. Given the systematic difference in firm size between the treatment and control groups, it may be of particular concern if changes in outcome variables would be the same in the absence of the program during the program period. Because we have more than two years of data before the program started, we can see whether the pre-intervention time trends are the same for the control and treatment groups. If they are the same before the program as is the case in our context, it will lend some support for the assumption that they are the same after the program started.

The second assumption is that the start of the EU ETS program is mean independent of the error term. This assumption could be violated if EU started the program in response to time-varying factors that affect outcome variables such as employment and specific to the treatment group. However, this violation is unlikely to happen given that the EU ETS was a way to fulfill EU obligations from Kyoto protocol and to combat climate change.

## 5. Empirical results

### 5.1. Power generation sector

In this section, we present results for firms in the power generation sector. We present results for four specifications for each of the three regressions on employment, material costs, and turnover. The first regression is from OLS without controlling for firm fixed effects and time effects. The second regression includes firm fixed effects while the third regression has both firm fixed effect and country-year fixed effects. The fourth regression adds interaction terms between program participation dummy with permit allocation and usage variables.

Table 4 shows parameter estimates and clustered standard errors (at the firm level) for the first regression where the dependent variable is the number of employees (in log). The results from the first two specifications suggest that the program increased employment among participants in both phases. However, the parameter estimates for the third regressions suggest

[10] As the equation takes the semi-logarithmic functional form and $d_{it}$ is a dummy variable, a consistent and unbiased estimator for the percentage impact of the dummy regressor on the leveled dependent variable is $\exp(\hat{\alpha} - \mathrm{var}(\hat{\alpha}/2)) - 1$.

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Table 4
Results on employment for power companies.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.546$^{nnn}$ | 0.0792$^{n}$ | └ 0.0277 | └ 0.176 |
| | (4.01) | (1.80) | (└ 0.46) | (└ 0.92) |
| Phase 2 participation | 0.372$^{nnn}$ | 0.125$^{nn}$ | └ 0.0198 | └ 0.326 |
| | (2.80) | (1.96) | (└ 0.23) | (└ 1.45) |
| Phase 1┘ log (surrendered) | | | | 0.0268 |
| | | | | (1.55) |
| Phase 2┘ log (surrendered) | | | | 0.0944$^{nnn}$ |
| | | | | (3.19) |
| Phase 1┘ log (allocated) | | | | └ 0.0153 |
| | | | | (└ 0.82) |
| Phase 2┘ log (allocated) | | | | └ 0.0696$^{nnn}$ |
| | | | | (└ 2.67) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 3262 | 3262 | 3262 | 3262 |
| Adjusted $R^2$ | 0.012 | 0.003 | 0.066 | 0.070 |

Note: Dependent variable is the logarithm of number of employees. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.

$^{n}$ Indicate significance at the 10 percent levels.

$^{nn}$ Indicate significance at the 5 percent levels.

$^{nnn}$ Indicate significance at the 1 percent levels.

Table 5
Results on unit material cost for power companies.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.125$^{nnn}$ | 0.0693$^{nnn}$ | 0.0479$^{nnn}$ | 0.0532 |
| | (7.88) | (6.92) | (3.82) | (1.16) |
| Phase 2 participation | 0.110$^{nnn}$ | 0.0895$^{nnn}$ | 0.0820$^{nnn}$ | 0.00664 |
| | (5.92) | (6.80) | (4.41) | (0.10) |
| Phase 1┘ log (surrendered) | | | | └ 0.00448 |
| | | | | (└ 0.85) |
| Phase 2┘ log (surrendered) | | | | └ 0.0124 |
| | | | | (└ 1.17) |
| Phase1┘ log (allocated) | | | | 0.00428 |
| | | | | (1.06) |
| Phase 2┘ log (allocated) | | | | 0.0191$^{n}$ |
| | | | | (1.75) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 3712 | 3712 | 3712 | 3712 |
| Adjusted $R^2$ | 0.036 | 0.042 | 0.101 | 0.107 |

Note: Dependent variable is the unit material cost, defined as the ratio of total material cost to operating revenue. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.
**Indicate significance at the 5 percent levels.

$^{n}$ Indicate significance at the 10 percent levels.

$^{nnn}$ Indicate significance at the 1 percent levels.

that the program decreased employment in power companies under the program by about 3 percent in the first phase and 2 percent in the second phase.

Nevertheless, both effects are not statistically significant from zero. The last specification interacts program participation dummy variables with allowances surrendered and allocated. The results suggest that there is no heterogeneous effect across firms with different levels of allowance usage and allocation during the first phase. Under the second phase, a larger allowance usage is associated with a larger employment while a larger allocation is associated with fewer employees. The number of allowance surrendered is likely affected by unobserved idiosyncratic factors at the plant level that affect production and hence emissions. So we restrain from interpreting these coefficients as causal effects.

Table 5 presents estimated effects on material costs. The first three specifications all suggest a positive impact on material costs from program participation. The third specification with firm fixed effects and country-year fixed effects provides the smallest estimates: about 5 percent increase in phase one and 8 percent increase in phase two. Because the power sector as a whole faced a binding constraint of $CO_2$ emissions during the study period, the increase in material costs could reflect the additional compliance costs incurred for purchasing allowances and/or switching from coal to natural gas.[11] It could also reflect the impact of parallel renewable incentive policies (such as feed-in tariffs and renewable portfolio standards) if large fossil fuel power suppliers that are covered by EU ETS are also more likely to be affected by the requirement of the renewable incentive policies.[12] The exact mechanism is, however, unlikely to be pinned down under the current analysis because material costs are only reported at the consolidated level. The fourth specification with interactions shows that the increase in material costs is larger among firms with a larger allocation of permits.

The results for firm turnover are shown in Table 6. The first two specifications suggest that the program increased turnover in both phases while the third specification with firm fixed effects and country-year fixed effects shows no statistical significant effect on average in the first phase and an almost 30 percent increase in the second phase. The increase in turnover could come from an increase in output or in price or in both components. Intuitively, an increase in material costs could lead to an increase in electricity prices. Since electricity demand is highly inelastic in the short-run, the price increase could translate into an increase in turnover. The fourth specification with interaction terms suggests that the increase in turnover is larger among firms with a larger usage in both phases. On the other hand, a larger allocation of allowances is associated with a smaller turnover in the second phase. Both findings could reflect utilities passing the cost (from compliance) to consumers.

Our analysis shows that the EU ETS in the first two phases had no statistically significant impact on the number of employees among power companies under the program. Given that electricity markets are mostly national and electricity demand is relatively inelastic, the program is unlikely to hinder the competitiveness of the power companies in the form of reduced demand. Nevertheless, the program is associated with increased material costs, most likely due to extra compliance costs to meet emissions commitments or other renewable programs. In addition, the regressions also show a positive impact on firm turnover. Whether the increase in turnover will dominate the increase in material costs and other costs, i.e., the impact of the program on profit, is left for future research.

### 5.2. Cement

Tables 7–9 present estimation results on employment, material costs and turnover for the cement industry. The model specification in each column is the same as those in the previous section. The fixed-effects model with firm and country-year dummies is again our preferred specification.

[11] Considine and Larson (2009) find evidence of interfuel substitution between coal and less carbon intensive or carbon free energy sources in electricity generation following the introduction of EU ETS.

[12] All countries in the study had implemented some kind of renewable incentive programs during the study period. Under a feed-in tariff mechanism, utilities are required to purchase power from renewable resources at a price higher than the market electricity price. Under a renewable portfolio standard, electricity suppliers must purchase tradable green certificates or otherwise supply renewable energy for a certain percentage of their total end-use delivery.

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Table 6
Results on turnover for power companies.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.439$^{nnn}$ | 0.430$^{nnn}$ | 0.067 | └ 1.417$^{nnn}$ |
| | (4.24) | (6.65) | (0.79) | (└ 3.85) |
| Phase 2 participation | 0.634$^{nnn}$ | 0.716$^{nnn}$ | 0.299$^{nn}$ | └ 1.161$^{nn}$ |
| | (5.75) | (8.08) | (2.40) | (└ 2.14) |
| Phase 1 ┘ log (surrendered) | | | | 0.144$^{nnn}$ |
| | | | | (3.71) |
| Phase 2 ┘ log (surrendered) | | | | 0.249$^{nnn}$ |
| | | | | (3.66) |
| Phase 1 ┘ log (allocated) | | | | └ 0.0175 |
| | | | | (└ 0.57) |
| Phase 2 ┘ log (allocated) | | | | └ 0.122$^{n}$ |
| | | | | (└ 1.79) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 4820 | 4820 | 4820 | 4820 |
| Adjusted $R^2$ | 0.016 | 0.039 | 0.127 | 0.140 |

Note: Dependent variable is the logarithm of operating revenue. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.

$^{n}$ Indicate significance at the 10 percent levels.
$^{nn}$ Indicate significance at the 5 percent levels.
$^{nnn}$ Indicate significance at the 1 percent levels.

Table 7
Results on employment for cement.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.420$^{nnn}$ | 0.0657 | └ 0.0220 | └ 0.0761 |
| | (3.37) | (1.28) | (└ 0.27) | (└ 0.29) |
| Phase 2 participation | 0.357$^{nnn}$ | 0.0549 | └ 0.0423 | └ 0.548 |
| | (2.84) | (0.93) | (└ 0.38) | (└ 1.55) |
| Phase 1 ┘ log (surrendered) | | | | 0.0618$^{n}$ |
| | | | | (1.83) |
| Phase 2 ┘ log (surrendered) | | | | 0.0756 |
| | | | | (0.73) |
| Phase 1 ┘ log (allocated) | | | | └ 0.0585 |
| | | | | (└ 1.61) |
| Phase 2 ┘ log (allocated) | | | | └ 0.0340 |
| | | | | (└ 0.32) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 1205 | 1205 | 1205 | 1205 |
| Adjusted $R^2$ | 0.017 | 0.004 | 0.034 | 0.062 |

Note: Dependent variable is the logarithm of number of employees. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.
$^{nn}$Indicate significance at the 5 percent levels.

$^{n}$ Indicate significance at the 10 percent levels.
$^{nnn}$ Indicate significance at the 1 percent levels.

Table 8
Results on unit material cost for cement.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | └ 0.0997$^{nnn}$ | └ 0.00232 | └ 0.0174 | └ 0.0648 |
| | (└ 5.52) | (└ 0.21) | (└ 1.18) | (└ 1.14) |
| Phase 2 participation | └ 0.0853$^{nnn}$ | 0.00533 | └ 0.015 | └ 0.123 |
| | (└ 4.65) | └ 0.44 | (└ 0.79) | (└ 1.61) |
| Phase 1 ┘ log (surrendered) | | | | 0.00665$^{n}$ |
| | | | | (1.76) |
| Phase 2 ┘ log (surrendered) | | | | 0.0272 |
| | | | | (1.03) |
| Phase 1 ┘ log (allocated) | | | | └ 0.00285 |
| | | | | (└ 0.77) |
| Phase 2 ┘ log (allocated) | | | | └ 0.0183 |
| | | | | (└ 0.65) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 1080 | 1080 | 1080 | 1080 |
| Adjusted $R^2$ | 0.068 | └ 0.001 | 0.085 | 0.091 |

Note: Dependent variable is the unit material cost, defined as the ratio of total material cost to operating revenue. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.
$^{nn}$Indicate significance at the 5 percent levels.

$^{n}$ Indicate significance at the 10 percent levels.
$^{nnn}$ Indicate significance at the 1 percent levels.

Table 9
Results on turnover for cement.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.160 | 0.340$^{nnn}$ | └ 0.125 | └ 0.405 |
| | (1.03) | (4.29) | (└ 1.04) | (└ 1.00) |
| Phase 2 participation | 0.251 | 0.368$^{nnn}$ | └ 0.159 | └ 0.679 |
| | (1.63) | (4.23) | (└ 1.08) | (└ 1.39) |
| Phase 1 ┘ log (surrendered) | | | | 0.0949$^{n}$ |
| | | | | (1.78) |
| Phase 2 ┘ log (surrendered) | | | | 0.0839 |
| | | | | (0.86) |
| Phase 1 ┘ log (allocated) | | | | └ 0.0747 |
| | | | | (└ 1.41) |
| Phase 2 ┘ log (allocated) | | | | └ 0.0409 |
| | | | | (└ 0.40) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 1259 | 1259 | 1259 | 1259 |
| Adjusted $R^2$ | 0.002 | 0.070 | 0.252 | 0.270 |

Note: Dependent variable is the logarithm of operating revenue. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.
$^{nn}$Indicate significance at the 5 percent levels.

$^{n}$ Indicate significance at the 10 percent levels.
$^{nnn}$ Indicate significance at the 1 percent levels.

In Table 7, the pooled regression in column (1) shows that participation in the first two periods of the trading is associated with a strong and significant increase in employment. These higher estimates are likely driven by the systematic difference between regulated and unregulated firms—EU ETS firms are larger with higher production capacity. Once controlling for the fixed firm-level differences (column (2)), the parameter estimates on program participation become much smaller and are no longer statistically significant. Column (3) considers the possible heterogeneity in the time trends among participating nations. The results indicate that employment reduced by 2 and 4 percent, respectively, during the first and second phase of the program. However, these effects are statistically insignificant. Column (4) shows that controlling for the allocation and surrender of allowances does not change the results.

Table 8 presents the estimation results on material costs. The OLS model suggests that EU ETS firms have lower material costs by 9 to 10 percent compared to their unregulated counterparts. The difference could be explained by the fact that larger firms are more efficient at production due to economies of scale. In contrast to the OLS results, the negative correlation disappears in fixed effects models. Based on our preferred estimator in column (3), firm material costs slightly reduce due to participation in the carbon trading. However, this effect is not significant at any reasonable level of confidence. Column (4) shows that a one percent increase in the usage of allowances in phase 1 is associated with a 0.7 percent increase in the material costs. As explained earlier, because allowances and other material inputs are both likely to be correlated with unobserved exogenous shocks, we do not interpret the result as a causal effect.

Table 9 summarizes regression results on the determinants of firm turnover. The estimated parameters of the OLS and firm fixed effects models in columns (1) and (2) suggest that participating in EU ETS is associated with a large and statistically significant (in the case of fixed-effects model) increase in turnover. We suspect this

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seemingly counterintuitive result could be explained by country-specific shocks contemporaneous with the implementation of EU ETS. For example, some countries may have facilitated state aid to balance the impact of the carbon regulation. Indeed, once we control for country-year fixed effects as in our preferred specification in column (3), the correlation between program participation and firm turnover becomes negative and statistically insignificant from zero. The column (4) shows that higher consumption of allowances in phase 1 is associated with larger amount of turnover. This correlation is more likely driven by factors such as demand shocks that simultaneously influence emission and outputs.

Overall, the above results suggest that EU ETS is neither detrimental nor profitable for the cement industry. There is also little evidence to support carbon leakage.

Table 10
Results on employment for iron and steel.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.631*** | 0.0552 | −0.102 | −1.012** |
| | (3.38) | (0.42) | (−0.60) | (−2.05) |
| Phase 2 participation | 0.441** | 0.146 | 0.00211 | −0.756 |
| | (2.28) | (1.29) | (0.01) | (−1.08) |
| Phase 1 × log (surrendered) | | | | 0.0803* |
| | | | | (1.70) |
| Phase 2 × log (surrendered) | | | | −0.00854 |
| | | | | (−0.10) |
| Phase 1 × log (allocated) | | | | 0.000179 |
| | | | | (0.01) |
| Phase 2 × log (allocated) | | | | 0.0743 |
| | | | | (0.79) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 902 | 902 | 902 | 902 |
| Adjusted $R^2$ | 0.029 | 0.002 | 0.003 | 0.002 |

Note: Dependent variable is the logarithm of number of employees. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.

* Indicate significance at the 10 percent levels.

** Indicate significance at the 5 percent levels.

*** Indicate significance at the 1 percent levels.

Table 11
Results on unit material cost for iron and steel.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | −0.0188 | 0.0134 | −0.00786 | 0.0335 |
| | (−1.04) | (1.27) | (−0.53) | (0.54) |
| Phase 2 participation | 0.0192 | 0.0430*** | 0.0250 | −0.0857 |
| | (1.07) | (3.37) | (0.83) | (−0.98) |
| Phase 1 × log (surrendered) | | | | −0.00125 |
| | | | | (−0.20) |
| Phase 2 × log (surrendered) | | | | −0.0356 |
| | | | | (−1.37) |
| Phase 1 × log (allocated) | | | | −0.00215 |
| | | | | (−0.35) |
| Phase 2 × log (allocated) | | | | 0.0438 |
| | | | | (1.54) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 950 | 950 | 950 | 950 |
| Adjusted $R^2$ | 0.003 | 0.033 | 0.080 | 0.096 |

Note: Dependent variable is the unit material cost, defined as the ratio of total material cost to operating revenue. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.

*Indicate significance at the 10 percent levels.

**Indicate significance at the 5 percent levels.

*** Indicate significance at the 1 percent levels.

Table 12
Results on turnover for iron and steel.

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Phase 1 participation | 0.533*** | 0.483*** | −0.0484 | 0.172 |
| | (3.44) | (4.39) | (−0.30) | (0.41) |
| Phase 2 participation | 0.239* | 0.404*** | 0.117 | 0.592 |
| | (1.70) | (3.65) | (0.51) | (1.01) |
| Phase 1 × log (surrendered) | | | | −0.00092 |
| | | | | (−0.02) |
| Phase 2 × log (surrendered) | | | | 0.0498 |
| | | | | (0.46) |
| Phase 1 × log (allocated) | | | | −0.0195 |
| | | | | (−0.46) |
| Phase 2 × log (allocated) | | | | −0.0897 |
| | | | | (−0.86) |
| Plant fixed effects | No | Yes | Yes | Yes |
| Country-by-year fixed effects | No | No | Yes | Yes |
| Observations | 987 | 987 | 987 | 987 |
| Adjusted $R^2$ | 0.022 | 0.054 | 0.281 | 0.279 |

Note: Dependent variable is the logarithm of operating revenue. Standard errors are clustered at the firm level and t statistics are shown in the respective parentheses.
**Indicate significance at the 5 percent levels.

* Indicate significance at the 10 percent levels.

*** Indicate significance at the 1 percent levels.

### 5.3. Iron and steel

Lastly, we run similar regressions for firms in the iron and steel industry, and the results are in Tables 10–12. From Table 10, column (1) shows that the two phases of EU ETS led to a statistically significant increase in employment, which can be seen from the summary statistics in Table 3. As argued above, this result is not valid if there are other unobserved effects that may be correlated with the participation as well as the dependent variable (employment). Columns (2) and (3) therefore control for firm fixed effects and country-by-year fixed effects. We can see that in column (3), after controlling for unobserved time-invariant firm-specific effects and time-variant country-specific effects, the EU ETS participation in Phase 2 has no effect on employment, though Phase 1 participation shows a non-significant 10 percent decrease. Most of the effects in column (1) are absorbed into the firm fixed effects. Column (4) controls for allowances allocated and surrendered. We can see that there is a positive effect of surrendered permits on employment of Phase 1 participated firms, though that may be caused by the positive production shocks that increase both labor and pollution.

Table 11 tabulates the results for unit material cost. The OLS result in column (1) shows that there are no statistically significant relationship between EU ETS participation and unit material cost. The fixed effects model in column (2) implies the Phase 1 of EU ETS increases the unit material cost of steel plants by about 4.3 percent. However, after controlling for possible policy responses by participating countries, the effect decreases to around 2.5 percent and it is no longer statistically significant. In both cases the Phase 1 appears to have no impact on the iron and steel plants too—before and after controlling for the country-by-year dummies, Phase 1 participation increases the unit material cost by 3.3 percent and decreases that by 0.8 percent respectively, and both effects do not appear to be statistically significant too. From column (4) it appears that there is correlation between unit material cost, Phase 2 participation and allocated permits, but we are being cautious here on whether these results are causal for reasons explained earlier.

Finally Table 12 looks at the effect of EU ETS on firm operating revenue. Both the OLS results and the fixed effects results show a positive and statistically significant relationship between EU ETS

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and firms' turnover. These results suggest that Phase 1 and Phase 2 of EU ETS increase the firms' sales by 48–53 percent and 24–40 percent, respectively. While it seems unintuitive that a cap-and-trade program (which increases their costs somehow) will increase revenue, this correlation can be explained by some revenue-improving country policies that are correlated with the program timing that also affects the participants. After controlling for time-varying country-specific factors in column (3), the effects significantly drop and become insignificantly different from zero.

## 6. Conclusion

The EU ETS is the first international cap-and-trade program for $CO_2$ and the largest environmental pricing regime in the world (European Commission, 2012). Covering more than 12,000 power stations and industrial plants in 30 countries, it is slated to finish its second phases and to further expand to more industrial sectors such as petrochemicals in 2013. Understanding the impacts of such a large scale environmental intervention on firms is important not only because it is a critical step to examine the cost-effectiveness of the program itself but also it can provide useful lessons for other countries and regions who are contemplating cap-and-trade programs such as China and India.

While there exists a large literature on the U.S. $SO_2$ allowance trading program, the world's first (and now virtually collapsed) large-scale cap-and-trade program, empirical studies on the EU ETS program is much scarcer. Our paper adds to this literature by investigating the impacts of EU ETS on material costs, employment and turnover for three main sectors: electric power, cement, iron and steel.

The program impacts on firms by EU ETS can be at best described as limited and isolated among the three sectors analyzed during the first phase (2005–2007) and the first part of the second phase (2008–2009). Our preliminary analysis showed only statistically significant effect on material costs and turnover among power plants and none were detected on any of the three variables of interests in cement, or iron and steel firms. Because the power sector as a whole was with a net short position of emission allowances, we conjecture that the increase in material costs among electric power firms could be linked to compliance costs associated with allowance purchasing and/or fuel switching from coal to natural gas. The rising material costs could also reflect the costs to fulfill obligations under the parallel renewable incentive programs which require utilities to purchase power from renewable resources at a price higher than the market price or to purchase tradable green certificates. The exact mechanism is however unlikely to be identified under the current analysis given the limited data availability. The increase in turnover in the second phase could partly reflect the cost pass-through to consumers in a market less exposed to competition outside EU. Our finding of no impacts for cement and iron and steel sectors suggests that concerns over carbon leakage, job loss and industry competitiveness are not substantiated at least during the study period. Lastly, the varying impacts underscore the validity of the sector-by-sector empirical approach.

It is important to note that these findings should be viewed in concert with the specific program period analyzed. As discussed in our introduction, the first phase of the EU ETS is a trial phase where abundance of allowances was allocated. Although the second phase aimed to reduce the $CO_2$ emissions by 6.5 percent below the 2005 level, the economic recession made the goal easier to achieve. In the future, we plan to extend the research in at least the following two directions. First, while we have analyzed material costs, employment and turnover so far, we have not examined the impact on firm profit yet. Second, we plan to include data from 2010 to 2012 in our analysis so that we can get a more complete picture of the impacts of the second phase of the program.

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